United States Court of Appeals

for the

District of Columbia Circuit

TRANSCRIPT OF RECORD

353

IN THE

UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA

No. 23740

ON PETITIONS TO REVIEW ORDERS OF THE FEDERAL POWER COMMISSION

JOINT APPENDIX

PIPELINE PRODUCTION AREA RATE CASE
CITY OF CHICAGO, ILLINOIS
CITY AND COUNTY OF DENVER, COLORADO
THE MEMPHIS LIGHT, GAS AND WATER DIVISION
MEMPHIS, TENNESSEE
AND THE AMERICAN PUBLIC GAS ASSOCIATION,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent.

United States Court of Appeals
for the District of Columbia Circuit

FILED SEP 1 1 1970

Nathan J. Paulson
CLERK

VOLUME I

(Page 1 to Page 386)

Washington, D. C. · THIEL PRESS · 202 · 393-0625

TABLE OF CONTENTS

EXCERPTS FROM PRE-HEARING CONFERENCE

[63]

I do not visualize one of these lengthy problems. We have a very constructive source of data from the all area questionnaires almost half of which were submitted by pipelines and their affiliates, as inordinate expense, I would say it was well into the hundreds of thousands of dollars to prepare that material. Certainly I know from the Commission, from its statements to the Congress about the all-area questionnaire, you recall it was called the ten pounder, did not intend to start out on another data gathering device such as Mr. Berkeley is referring to.

MR. BERKELEY: We have a proposed stipulation of facts which we will introduce at the appropriate time, and it includes all responses to the all area questionnaire. There will be no need for duplication, Mr. Shibley. We are talking about new data which bears directly on these issues and has never been introduced before.

[209]

[PRESIDING EXAMINER] * * * Unless someone raises a question at the next pre-hearing conference, the presumption will be that it was stipulated.

MR. WERNER: That is fair enough.

MR. KILBOURNE: I might mention to you that Section 1.25 of the Rules of Practice and Procedure states that all parties must stipulate, and if anyone does not stipulate the stipulation is not in effect and it would require an order by yourself. I agree this was the situation in the past area rate proceedings and probably will be the one here, that upon granting of our intervention we would oppose stipulating all items in this document at this particular time prior to your order.

PRESIDING EXAMINER: Thus far we don't have an opponent yet.

[209]

MR. KILBOURNE: Upon intervention being granted, we will.

PRESIDING EXAMINER: Well, we will take that under consideration.

[244]

MR. SHIBLEY: That is half of it. The other half of it is the material which was compiled largely from the all-areas questionnaire response, some of it Form 2 and other material, which we have incorporated by reference from the AR 64-1 record, I am assuming that the staff is raising no question as to that material. I don't mean as to the effect of it, but as to our including it in the record in this proceeding, and therefore we don't have to go through the process of requesting the data again.

MR. BERKELEY: Certainly not. Staff agrees, and I think everybody else agrees, that the evidence you put in AR64-1 can be incorporated in this record and you can supplement it as you wish.

[251]

PUBLISHED STATISTICAL DATA
MATERIAL INCLUDED IN STIPULATION
IN DOCKET NO. RP66-24 PROCEEDING

1. Statistical data on natural gas, natural gas liquids, crude petroleum, coal and other fuels as compiled and published by the Bureau of Mines.[1]

2. Census of Mineral Industries, 1939, 1954, 1958, 1963 (Crude Petroleum and Natural Gas, Oil and Gas Field Contract Services and Natural Gas Liquids Sections).

[1] The Bureau of Mines data on hydrocarbons were compiled in accordance with the procedures outlined in (and are to be used in the light of) the definitions and descriptions of data contained in attached B hereto.

3. Wholesale Price Index and components thereof, compiled and published by the Bureau of Labor Statistics (Wholesale Prices and Price Indices).

4. Consumer Price Index and components thereof, compiled and published by the Bureau of Labor Statistics.

5. Platt's Oil Price Hnadbook and Oilmanac and predecessor publications and Platt's Oilgram - Price Service: Posted Price of Fuel Oil.

6. National Electric Rate Service (Federal Power Commission).

7. New Construction of Natural Gas Facilities Authorized (Federal Power Commission).

8. Gas Rate Service (American Gas Association).

9. Annual Reports to the Federal Power Commission (Form 1, Form 2, Form 4, Form 11, Form 15, Form 120 and Form 301).

10. Annual Reports of corporations to stockholders and to governmental agencies.

11. Moody's Investor Service: Moody's Industrial Manual, Moody's Transportation Manual and Moody's Public Utility Manual; Standard and Poor's Corporation Records; Standard & Poor's Monthly Stock Guide; Standard & Poor's Monthly Bond Guide; Standard & Poor's Trade and Securities Statistics; Moody's Handbook of Widely Held Common Stocks.

12. Federal Reserve Board, Federal Reserve Bulletin.

[252]

13. Federal Reserve Board, Federal Reserve Bulletin.

14. Securities and Exchange Commission, Statistical Bulletin.

15. Fortune Magazine, July issues on the 500 largest industrial corporations.

16. Oil and Gas Field Development in United States and Canada, National Oil Scouts and Landmens' Association Yearbook, annual issues.

17. International Oil and Gas Development, Yearbook annual issues, International Oil Scouts Association and Society of Petroleum Engineers of AIME.

18. American Institute of Mining, Metallurgical and Petroleum Engineers, Petroleum Branch Statistics of Oil and Gas Development and Production and successor publication of the International Oil Scouts Association and Society of Petroleum Engineers of AIME, annual issues.

19. American Petroleum Institute–American Gas Association Committees on Reserves, Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas, annual issues.

20. National Petroleum Council–Proved Discoveries and Productive Capacity.

21. April Monthly Letter of First National City Bank, Business and Economic Conditions: Corporate Return on Net Assets.

22. Chase Manhattan Bank, Annual Analysis of The Petroleum Industry.

23. Number of wells and footage drilled, by type of well, as compiled and published by the Oil and Gas Journal.

24. Number of wells and footage drilled, by type of well, as compiled and published by World Oil.

25. Average Hourly Earnings of Petroleum Workers as published by the Bureau of Labor Statistics.

26. Statistical data on utility sales as compiled and published by American Gas Association.[2]

---

[2] The American Gas Association Sales Data were compiled in accordance with the procedures outlined in (and are to be used in the light of) the definitions and description of data contained in Attachment B hereto.

[253]

27. The C.D. Lockwood Company's Source Books of Petroleum Statistics for various states.

   A. Gas Processing Plants–Annual
   B. Well Potential Reports–Semi-Annual
   C. Gas Well Tests–Semi-Annual
   D. Annual Production–Gas
   E. Annual and Cumulative Production–Crude Oil by Lease
   F. Annual Production–Gas and Condensate From Gas Wells
   G. Annual Production by Operating Company
   H. Sweet Gas–Annual
   I. Casinghead–Annual
   J. Crude Oil–Annual

28. State Reports

   A. Rules and Regulations of the Texas Railroad Commission–Compiled and Published by R.W. Byram & Company
   B. Texas Railroad Commission; Monthly reported form 3-266-A data (1955 to date)
   C. Bulletin of State Geological Survey of Kansas (Annual)
   D. Oklahoma Tax Commission, Gross Production Division, Annual Reports to Oklahoma Geological Survey (no form number)
   E. Annual Reports of the Oil and Gas Division of the Railroad Commission of Texas (Annual)
   F. Oil and Gas Developments in Kansas. Published by the State Geological Survey of Kansas (Annual)
   G. General Rules and Regulations, issued by The State Corporation Commission of Kansas, compiled by General Counsel for the Commission, July 1958.

[254]

H. General Rules and Regulations of the Corporation Commission of Oklahoma, dated December 1, 1961

I. Louisiana Department of Conservation

J. Rules and Regulations–Oil and Gas–Compiled and Published by R.W. Byram & Company (Louisiana)

K. Annual Oil and Gas Reports (Louisiana)

L. Gas Production and Proration Orders (Louisiana)

M. Oklahoma Corporation Commission Files

N. Monthly Summary of Texas Natural Gas (by months) as Reported to the Railroad Commission of Texas Oil and Gas Division.

O. Publications of the Texas Railroad Commission.

1. Monthly Summaries of Texas Natural Gas
2. Annual Reports of Oil and Gas Division
3. Annual Report of Gas Utilities Division
4. Annual Report of Gas Utilities filed with the Oil and Gas Division
5. Proration Reports
6. Reports of Naming Oil and Gas Fields

P. State Corporation Commission, State of Kansas Conservation Division:

A. Proration Reports and Orders

B. Natural Gas Production by Field (annual)

Q. Corporation Commission of Oklahoma:

A. Proration Reports

B. Classification of Pools and Allowables

C. Bimonthly Orders Allocating Gas and Oil Production

[255]

R. State Geological Survey of Kansas:

A. Oil and Gas in Eastern Kansas, Bulletin 104 (1954)

B. Oil and Gas Developments in Kansas during 1963, Bulletin 172 (annual)

C. The Geologic History of Kansas, Bulletin 162 (1963)

S. Oil and Gas Reports of other Producing States

29. Exhibit "H" to pipeline certificate applications (Federal Power Commission).

30. Rinehart Oil News

31. FPC, Steam Electric Plant Construction Cost and Annual Production Expenses (Annual).

32. Edison Electric Institute, Annual Statistical Bulletin.

33. Sales Management Magazine, Survey of Buying Power, Annual.

34. Chase Manhattan Bank, Petroleum Situation (Annual).

35. U.S. Department of Labor, Bureau of Labor Statistics, Employment and Earnings (Annual).

36. U.S. Department of Labor, Bureau of Labor Statistics, Statistical Tables on Manpower, from Manpower Report of the President, March, 1963.

37. Interstate Commerce Commission, Carload Waybill Statistics.

38. U.S. Department of Commerce, Weather Bureau, Local Climatalogical Data (Annual).

39. American Petroleum Institute, Petroleum Facts and Figures.

40. American Gas Association, Gas Facts.

41. American Gas Association, Historical Statistics of the Gas Industry

[255]

42. Bureau of the Census, Census of Population, and Inter-Census Population Estimates.

[256]

43. FPC, Sales by Producers of Natural Gas to Natural Gas Pipeline Companies.

44. National Coal Association, Steam Electric Plant Factors.

45. National Coal Association, Trends In Electric Industry Experience.

46. National Coal Association, Bituminous Coal Data.

47. American Association of Petroleum Geologists, Well Drilling and Completion, Exploration and Development Data.

48. U.S. Department of Commerce, Survey of Current Business.

49. Joint Association Surveys–IPAA, Mid-Continent Oil and Gas Association.

50. Semi-Annual Reports of the Cost Study Committee, Independent Petroleum Association of Amierca.

51. Oil & Gas Journal, annual active field survey.

52. Data on contract drilling prices, Published in Drilling Contractor (American Association of Oil Well Drilling Contractors).

53. American Petroleum Institute, *Statistical Bulletin*, weekly issues.

54. *The Oil and Gas Journal*, Lease Condensate Production.

55. *World Oil*, Lease Condensate Production.

56. *Petroleum Engineer*, Deep Drilling Report (March issues).

57. *Quarterly Financial Reports for Manufacturing Corporations*, Federal Trade Commission and Securities and Exchange Commission–all years.

58. American Gas Association Committee on Natural Gas Reserves, Estimated Proved Recoverable Reserves for Natural Gas by FPC Pricing Area for the Years 1956 to 1964, Inclusive.

59. Statistical Studies and Reports Prepared by the Statistics Division, Internal Revenue Service, United States Treasury Department. This would include Statistics of Income–Corporation Income Tax Return–compiled annually with the underlying work sheets gathered into a "Source Book of Statistics of Income."

[272]

[MR. BERKELEY]

I do not wish to mislead you, sir. I think you are entitled to a candid statement of how far we have gone. We have agreement, I think, on by far the major portion of the questionnaire. We have disagreements as to a relatively few matters of principle. I won't burden you, sir, or attempt to breach the wall we have set up between our negotiations and your formal rulings, by identifying what these are, but I think you should be aware, Mr. Examiner, that we have reached what appear to be some irreconcilable differences on matters of principle and on matters of the relevance of particular questionnaire items.

Those will have to be resolved by yourself, Mr. Examiner. The parties will be unable to resolve them.

However, I do feel that this questionnaire is unusually important. This is a policy-making proceeding. It is a proceeding in which we are working in an area where the Commission has never had any comprehensive evidentiary record, and this basic questionnaire will be the foundation stone on which all the evidence and testimony of all the parties will rest.

I think it is fair to state that it is a basic data questionnaire that will be used not only by the Staff to prepare its evidence, but all the other parties who wish to prepare evidence as well willl make use of it.

[273]

A brief review of the chronology of our dealings with the questionnaire will give you the best measure of the progress we have made. On May 18 we distributed the first version of the Staff's questionnaire to the parties. On June 14 and 15 we had an informal conference on the questionnaire.

We received their versions. As a result of this we made extensive revisions and sent out a revised questionnaire on June 22. That was about seven days after the end of the conference. This was discussed six days later on June 28 and 29.

We will send out our new revision on July 19, eight days after we receive the final comments of the parties. Seven days after that mailing on July 28, we will have another informal conference. We anticipate, sir, in a matter of two days after that we will be ready to go back on the record and submit any remaining disputes to you for formal evidentiary ruling.

[Excerpts From Transcript of Proceedings]

* * *

[TESTIMONY OF FELIX I. SHAFFNER]

[491]

Q. Dr. Shaffner, what is the purpose of your testimony in these proceedings? A. The purpose of my testimony is these proceedings is to assist the Examiner and the Commission in determining the proper rate of return and income tax treatment for pipeline produced natural gas.

Q. Do you recommend that either cost-of-service or area rate treatment be used to regulate pipeline produced gas? A. No. I note some of the factors of administrative feasibility mentioned in *Phillips Petroleum Co.*, 24 FPC 537, 545-546, which, among other things, led the Commission

to adopt area rate pricing for independent producers. However, this necessity is not present in the case of pipelines. Unlike the situation presented by producer regulation, "just and reasonable" cost-based rates have already been established and presumably are now being applied to pipeline produced gas. The Commission is not faced with the immediate need (as it was in the case of independent producer regulation) to establish rates with a minimum delay for both old and new reserves and for all gas sold in interstate commerce. Thus, the Examiner and the Commission here have the opportunity to adopt the best possible mode of regulation for pipeline production with regard to its experience with

[492]

both area rate and individual pipeline cost of service regulation without regard to factors of urgency.

Whether cost of service or area rates should ultimately be recommended in this proceeding is a policy question which I defer to witnesses concerned with overall Commission policy. However, to assist in the determination of this question I wish to discuss significant differences with regard to financial needs of pipeline production and independent producer production which would affect the rate of return to be allowed for pipeline production. These differences would apply regardless of the pricing method ultimately adopted by the Commission.

Q. Then will you recommend a specific return or tax component to be included in the ultimate rates reached as a result of these proceedings? A. No. Of course, if individual company cost of service for pipelines is continued, no specific rates of return need be adopted now. They would be determined as a result of individual company rate hearings or settlements. I would recommend that even if area rate treatment is adopted that the application of a specific return and/or tax component be left to individual cases.

[492]

Q. What is the reason for this? A. As the Commission noted in Opinion 468, area rate treatment has the advantages of fixing a price for gas produced rather than for the producer. Furthermore, area rates, especially under the two-price system, create incentives for the efficient, low cost producer. These factors would point to the adoption of area rate treatment, at least for new reserves. However, the adoption of area rates should not require

[493]

indiscriminate application of all components comprising the area rate to pipeline produced gas regardless of facts which warrant rate differences. While I am cognizant that area rate pricing would normally assume a single return and tax component, I think that it would be preferable to set these amounts with reference to the needs of the individual companies. With regard to Phase I, in which area rates might be applied for future production, it may make sense to say that a production or exploration cost standard should be uniformly set for all pipeline produced gas, or for all pipeline produced gas in a particular area. Doing this would tend to advantage and encourage low cost production. Such pricing would place pipeline producers on an equal footing among themselves and between themselves and producers and would give all the same rewards for efficiency. However, the necessary return for pipelines varies among companies. Since necessary return in large part is related to overall company functions, I would suggest that this item be continued to be separately determined for each producing pipeline and be allowed to it in place of the return component in the area rates. This would have the effect of not charging the consumer more than necessary, but gearing the return (apart from any "incentive" return resulting from the application of area rates) to the needs of the company involved.

Q. What about Federal income tax? A. I shall discuss the application of the tax expense to pipeline production costs later in my testimony.

Q. Do you have any reason to believe that the allowed overall return on pipeline production should be lower than that allowed independent

[494]

producers? A. Yes. Pipeline company financing is less expensive, as a rule, than that of independent producers. To allow pipelines and producers an equivalent rate of return on their production would not give the pipelines and their stockholders "parity," but would give them preferential treatment. Since pipelines have reduced financing costs, "parity" would give their stockholders a greater—and in my opinion unnecessary—return on their common equity investment.

Q. Can these differences be seen from a comparison of the typical capital structures of pipelines and independent producers? A. Yes. If you will refer to schedules 1 and 2 of my Appendix A attached, you will see that I have set forth the capital structures for the leading pipeline companies and for the leading independent producers. My estimate is that a typical pipeline capitalization from 1955-1965 would average about 60.5 percent long-term debt, about 8.1 percent preferred stock and about 31.4 percent common equity; a typical independent producer capitalization would show, in 1962, about 14 percent long-term debt and less than 1 percent preferred stock and the remainder as common equity. It should be noted that the above pipeline capitalization ratios ignore the factor of deferred Federal Taxes arising from rapid depreciation or amortization, a portion of which are still included in capitalization, but which had no cost to the company. The ratios ignore also the fact that the data is not adjusted for rate case settlements, as is noted in various tables in the source given. The effect of these settlements and Commission orders may reduce the rate of return on the rate base and reduce the

[495]

proportion of common equity capital, particularly if a refund is financed by long-term debt.

Q. What is the significance of these differences in the capitalization structures of pipelines and independent producers? A. Since debt costs less than equity, the greater a company's debt, the greater will be the proportional rate of return on common equity at any given overall rate of return. Thus, as to overall return in the case of pipelines, a return of about 6-¼ percent or 6-½ percent might produce double that percent of return on equity. However, because of their proportionately lesser amounts of debt, in the case of independent producers an overall return of 10-½ percent to 12 percent would produce a return on equity that is only about 1 percent to 1-1/2 percent higher than the overall return. Thus, the overall rate of return required to produce a given allowance on common equity is much lower for pipelines than for the independent producer because of the much greater resort to "leverage", or the percent of long-term debt and preferred stock in the pipelines' capital structures compared to the independent producer's.

Q. Can you illustrate this effect? A. Yes. The effects of leverage can readily be seen from two recent cases in which I testified. I refer to the *Panhandle* case, 25 FPC 787, 802 (Opinion 344) and the *El Paso* case 28 FPC 688, 702 (Opinion 366). From the capitalization structures of those companies, it can be seen that to have allowed an overall rate of return of 10-1/2 percent would have resulted in a return on equity of 26.11 percent for Panhandle and 32.86 percent for El Paso. To have allowed a return of 12 percent would have resulted in returns on common equity of 30.74 percent and 40.01 percent, respectively. The arithmetical derivation would be as follows:

[496]

PANHANDLE (Opinion 344)
25 FPC 787,802

	Percentage Of Capitalization	Cost or Allowance		Rate Of Return At Overall Rate Of 12.0%	10.5%
Debt	60.35	x 2.90	=	1.75	1.75
Def. FIT	.54	x 1.50	=	.01	.01
Pfd. Stock	6.67	x 4.02	=	.27	.27
Equity	32.44	x 30.74[1]	=	9.97	8.47
	100.00			12.0%	10.5%

[1] If 10.5% is assumed then the return on common equity becomes 26.11%.

EL PASO (Opinion 366)
28 FPC 688, 702

Docket No. RO60-3:

	Percentage Of Capitalization	Cost or Allowance		Rate Of Return At Overall Rate Of 12.0%	10.5%
Debt	66.10	x 4.59	=	3.03	3.03
Def. FIT	3.33	x 1.50	=	.05	.05
Pfd. Stock	9.60	x 5.48	=	.53	.53
Equity	20.97	x 40.01[2]	=	8.39	6.89
	100.00%			12.0%	10.5%

[2] If 10.5% is assumed then the return on common equity becomes 32.86%.

[497]

Q. Should it matter for rate determinations that pipeline financing costs are less expensive so long as the risk to pipeline companies and independent producers would be the same? A. Whether as a matter of policy pipeline produced gas should receive the same price as producers produced gas is not for me to determine. However, I point out that because of overall pipeline company financing advantages, pipeline produced gas has lower capital costs. Investors do not invest in an isolated part of an integrated company's business, but in the company as a whole. Funds received from general company financing are usually available for use anywhere in the company's business. In fact, the Commission in its adoption of a rate of return for producers in *Permian* (34 FPC at 201) specifically referenced its there allowed return allowance to its experience with pipelines, pointing out that a 6.25 - 6.5 return for pipelines was in fact equal to 10.0 to 12.0 yield on equity. This factor should not be understated. Moreover, your question assumes that the risks of finding and producing gas for all corporate groups are about the same. But I have not seen evidence of this. In fact, the evidence points to the contrary. For one thing, cheaper pipeline financing would itself reduce the risk on pipeline production. For another thing, as has been noted by the Commission and courts, pipeline production has a greater assurance of demand for its gas than do independent producers. Pipelines have a captive market for any gas they may acquire. This would reduce the risk inherent in the production and sale of pipeline-produced gas. In fact, the Commission has stated that investors may prefer to invest in pipeline companies with their own reserves rather than in pipeline companies

[498]

without reserves. (13 FPC, 53, 99). Integration of the production and transportation functions can be an element creating financing strength not weakness. And, as has been

testified to by witness Zabel, pipeline production appears highly gas oriented. This would indicate that many pipelines do integrate their production and transportation activities. Also, it would appear that pipelines may tend to invest in less risky properties (i.e., producing in lieu of non-producing) and that therefore their production operations, considered separately and alone, would be subject to less risk?

Q. Are there other factors which might differently affect the risk of pipeline production vis-a-vis independent producer production? A. The advantages of having integrated transportation and producing functions might reduce the risk of pipeline productions in various ways. In fact, the advantages to pipeline production testified to by various pipeline witnesses such as "swing", etc., if true, would tend to reduce pipeline risk. Most advantages testified to relate to integrating production and transportation functions to get a more efficient overall operation. Such added efficiency would of course add to investor attractiveness. Furthermore, low quality pipeline production may be less of a risk because pipelines may be able and willing to blend poor quality packages of their own gas with their other supply or may be better able to absorb high cost packages of their own gas whereas producers must dispose of high-cost packages of gas for the best price they can obtain. I would further mention in this regard that even under area pricing pipelines unlike producers would not be tied down by negotiated

[499]

contract price limitations and would therefore presumably contract to themselves for the maximum FPC allowed rate. Under cost of service pricing pipelines could, of course, charge consumers amounts for production which far exceed producer allowed rates.

Q. Would the decline in the proportion of pipeline production to pipeline purchases indicate a too low historic rate of return? A. I do not believe so. As is well known,

[499]

just as independent producers expanded their production, pipeline companies expanded their pipeline transmission facilities tremendously after World War II to meet the increased demand for natural gas. Had pipelines expanded to meet both the demand for natural gas production and the demand for new transmission facilities as well, this would have necessitated much greater amounts of capital. After World War II the independent producers were already heavily committed to production activities, which on occasion resulted in the discovery of large gas reserves for which there was no ready market. However, given the large amount of shut-in or flared gas supply, they were then in a position to vastly increase their natural gas sales. There was no reachable market for much of this gas immediately after World War II. Because of the pressures for transmission facilities wrought by both the availability of this relatively inexpensive gas and by market demand, the pipelines markedly expanded their transportation facilities. Given this situation of both large amounts of shut-in gas and producer production capacity (at least in the early periods), plus the need for expansion of transmission facilities, in retrospect it seems natural that the pipelines chose to concentrate on expanding their trans-

[500]

mission facilities while purchasing most of their needed gas supplies.

Q. Does your testimony with regard to pipeline production rate of return apply to pipeline owned hydrocarbons extraction plants as well? A. Yes. As I have indicated, the applicable rate of return to be applied to individual company functions is so influenced by the overall operations of the company that it is difficult to see why any particular function should be accorded a different rate of return. Moreover, the Commission in *Permian* specifically recognized that plants were not entitled to a "production" rate of return. (See *Permian*, 34 FPC 1072).

Q. Are any tax benefits available from pipeline production? A. Yes, tax benefits arise from the statutory depletion allowance which permits 27-1/2% of revenues from production to be deducted from income taxes as long as this amount does not exceed 50% of net income, exclusive of the 27-1/2% calculation. Also the producer of gas is allowed to deduct his intangible drilling expenses, amounting to perhaps 75% of total drilling costs, from gross income. He is also allowed to deduct all the expenses of drilling dry holes from gross income in computing income tax. Dry holes, although worthless from a financial standpoint, provide a great deal of valuable geological information which assists the company in its future drilling operations.

Q. What benefits do these tax features provide the pipeline producer? A. They save the pipeline producer money that would otherwise go to the government in taxes and, to the extent that they eliminate taxes on production, and may spill over to save taxes on nonproduction income, they make it necessary to earn on equity capital only $1 before taxes (instead

[501]

of nearly $2 as in the case of a company subject to regular tax rates) in order to have $1 of equity earnings after taxes. I do not claim, however, that in the long run they necessarily increase the producer's rate of return, although in the short run that may also be a result.

Q. Should rates allowed for pipeline production take into account the tax benefits or tax losses attributable to gas production by pipelines? A. I am testifying to no more than seems clear, as a general proposition, that production does in fact generate tax benefits or tax losses. However, I make no recommendation with regard to the course which should be followed in designing rates for pipeline production. I note the Commission decisions have generally been based on the proposition that appropriate gas rates should reflect only taxes paid (there have been some deviations, most notably with respect to the treatment of some of the deferred income taxes).

[501]

I am informed by staff that they will recommend, that should area rates be allowed as a result of this proceeding, appropriate consideration of these tax benefits be considered on an individual company basis. This will allow any company to show that its production activities do not result in tax loses, if that is indeed the case, and will allow that company to be treated accordingly. The individual pipeline company tax treatment is similar to that which has been recommended with regard to the determination of an appropriate rate of return. Since these two items are so interrelated, I would think that they should be considered together on an individual company basis.

Q. Does this complete your testimony? A. It does.

* * *

[503]

CAPITAL RATIOS AND CAPITAL COSTS OVERALL RATE OF RETURN–ALLOWANCE ON COMMON EQUITY CLASS A AND B NATURAL GAS PIPELINE COMPANIES

December 31, 1962

Long Term Debt	61.0% @ 4.75%	=	2.90%
Preferred Stock	8.5% @ 4.97%	=	0.42%
Common Equity	30.5% @ z	=	?
			R

Allowed Return (R)	Allowances for Common Equity
6.25	9.61
6.50	10.43
9.50	20.26
10.50	23.54
12.00	28.46
16.00	41.57

Source: FPC Statistics of Natural Gas Companies, 1962.

[504]

CAPITAL RATIOS AND CAPITAL COSTS OVERALL RATE OF RETURN–ALLOWANCE ON COMMON EQUITY NATIONAL GROUP–INDEPENDENT PRODUCERS

December 31, 1962

Long Term Debt	13.9% @ 4.02%	=	0.56%
Preferred Stock	.5% @ 4.43%	=	0.02%
Common Equity	85.6% @ z =	=	?
			R

Allowed Return (R)	Allowance for Common Equity
8.00	8.67
8.50	9.25
9.00	9.84
9.50	10.42
10.00	11.00
10.50	11.59
11.00	12.17
11.50	12.76
12.00	13.34
16.00	18.01

Source: Annual Reports to Stockholders and Standard & Poor's Corporation Records.

This was Schedule No. 28, from Exhibit 8-J, AR64-1, 64-2, et al.
Eugoton Anadarke Area and Texas Gulf Coast Area.

* * *

[548]

TESTIMONY OF VICTOR H. ZABEL
Re: Comparison of Gas Reserves, Gas Production, and Related Factors Between Respondent Groups 1, 2, 3 and 4

[548]

Q. Will you please state your name and place of residence. A. My name is Victor H. Zabel and I reside in Arlington, Virginia.

Q. By whom are you employed and in what capacity. A. I am employed by the Federal Power Commission and am classified as a Geologist.

[570]

Q. What issue will you take up next. A. The Presiding Examiner next asked, "To what extent, and in what respects, do pipelines operate their production properties in a different manner than do independent producers with respect to:

[571]

(a) reserve to production ratio: (b) exploration and development as a percentage of total gross investment in producing lands; (c) total royalties per Mcf, segregated between land owner and overriding royalties; and (d) revenues earned from the sale of gas and from the sale of liquids." Of the several items in this issue only item (a), regarding reserve to production (R/P) ratios, can be answered by the gas supply schedules in the questionnaire.

Q. What can you say, then about the different manner in which pipelines operate their production properties. A. It may be inferred from R/P ratios, as well as annual gas withdrawal rate data, that producing pipeline companies did not produce their owned reserves at as great an annual rate as they did the gas reserves dedicated them by the independent producers and that the pipeline producers may

not have utilized their owned gas reserves as fully as did the independent producers.

Q. Would you explain the R/P ratio and withdrawal rate data to which you have referred. A. First I'd like to comment on the matter of gas reserve to production ratios, or R/P ratios. Please refer to Tables No. 2, 3 and 4 and Chart No. 3. These Tables and Chart illustrate, among other things, company owned reserves, production, R/P ratios and national R/P ratios for the years 1946 to 1965.

Table No. 2 and Chart No. 3 illustrate that Group 1 R/P ratios for company owned gas were lower than the national ratios for the

[572]

period 1946 to 1951 but thereafter the Group had significantly higher R/P ratios than the national ratios. Now compare this with the same data for affiliated producers as shown on Table No. 3 and Chart No. 3. Group 3, throughout the 1946 to 1965 period, had R/P ratios lower than the national ratios. Table No. 4 nad Chart No. 3 show that Group 4 R/P ratios exhibited a very erratic behavior from 1946 to 1958, but from 1958 to 1965 they were essentially the same as the national ratios.

Q. Is there any other way to illustrate the different production operations between producing pipelines and other producers. A. A comparison of the annual gas reserve withdrawal rates of the various types of producers may prove helpful. Please refer to Tables No. 17, 18 and 19 and Chart No. 7. It can be seen from Table No. 17 and Chart No. 7 that Group 1 producing pipelines withdrew their owned gas reserves at rates increasing from 3 percent in 1958 to 3.9 percent in 1965, while reserves purchased from independent producers were withdrawn by Group 1 companies during the same period at annual rates increasing from 4.3 percent to 5.5 percent. During the same period of time Group 1 companies withdrew gas from their affiliated companies at rates varying between 5.8 and 7.1 percent.

[572]

The relative importance of the 3 Group 1 sources of gas reserves is illustrated by the following tabulation developed from Table No. 17.

[573]

Date	Total Reserves From 3 Sources (MMcf)	Company Owned(%)	Pipeline Affiliates(%)	Independent Producers(%)
1958	139,453,602	15.5	5.0	79.5
1959	138,062,276	16.3	4.3	79.4
1960	146,674,649	16.5	3.9	79.6
1961	146,141,038	16.8	4.1	79.1
1962	145,442,204	16.2	4.5	79.3
1963	148,274,831	15.2	3.4	81.4
1964	147,603,149	14.6	3.5	81.9
1965	147,335,074	14.9	3.6	81.5

Table No. 18 and Chart No. 7 show the annual rate at which the Group 2 non-producing pipeline companies withdrew the reserves dedicated to them by independent producers to have varied from 3.4 percent in 1958 to 4.9 percent in 1965. The withdrawal rate from Group 2 affiliated companies varied from 1.3 percent in 1958 to 9.3 percent in 1965 but the importance of this source of gas supply diminished during that period of time. This is illustrated by the following tabulation developed from Table No. 18 which shows the reserves dedicated to Group 2 by the 2 sources.

Date	Total Reserves From 2 Sources (MMcf)	Pipeline Affiliated (%)	Independent Producers(%)
1958	24,126,329	7.5	92.5
1959	27,057,653	6.6	93.4
1960	27,517,670	6.2	93.8
1961	32,566,190	5.1	94.9
1962	33,541,157	4.4	95.6
1963	33,921,682	3.9	96.1
1964	36,099,005	0.1	100.0
1965	38,872,792	0.1	100.0

[574]

These data indicate that the Group 1 producing pipeline companies did not withdraw their owned gas reserves at as great as annual rate as they withdrew the reserves dedicated to them by independent producers and that they withdrew gas from their affiliated companies at rates even greater than that from the independent producers. The Group 1 companies also withdrew their owned gas at annual rates less than the Group 2 non-producing companies rate of withdrawal from independent producers.

* * *

[577]

TESTIMONY OF NORMAN DEUTSCH

Q. Please state your name and address. A. Norman Deutsch, 1900 Ladd Street, Silver Spring, Maryland.

Q. Please state your occupation. A. I am employed by the Federal Power Commission as Assistant to the Chief, Analysis and Procedures Division, Bureau of Natural Gas.

* * *

[580]

Q. What recommended disposition do you conclude is appropriate for Phase I of these proceedings? A. With respect to natural gas produced from leases acquired by pipelines after the issuance of the Commission's Order in Phase I, I recommend that the Commission adopt the policy of applying area reates to such production with the rate of return and federal income tax modifications discussed by Dr. Shaffner in his testimony.

My recommendation that the Commission provide modified area rate treatment to pipeline produced gas from future acquired leases stems from an amalgam of many considerations. Fundamentally, I conclude that the Commission should neither encourage nor discourage pipeline ownership of natural gas reserves and production. This is because there appear to be

[581]

no consumer benefits associated with pipeline production. This is not to say that no isolated situations to the contrary could not be shown. However, there is no evidence that pipeline produced gas has special operational and pricing characteristics, or is of such a substantial volume, so as to critically affect or shape the overall character of the gas producing and transmission industry. In fact the routinely asserted advantages of pipeline production do not appear to exist as substantial, meaningful benefits, if they exist at all. I speak of such claimed advantages as operational flexibility, price negotiating leverage, and the improvement of pipeline prepaid gas positions. Nor is there any reason to expect pipelines to produce gas less expensively than independent producers in the future. While there is old inexpensive production owned by some pipelines since the birth of the gas transmission business, future exploration and production costs should average out to the costs underlying the Commission's area rate determinations. Indeed, to the extent that the industry typically spreads risks by jointly sharing the working interest of well drilling among several entities, there would be a comparative identity of costs.

* * *

[583]

Another reason for recommending area rates for Phase I of this proceeding is that such regulatory standards appear more suited to solve certain problems presented by pipeline production. The application of area rates to pipeline production would aid in handling the administrative problems of regulation common to pipeline production as well as to other production. (E.g. collection of production cost data, data classifications.) A uniform area rate standard which provides encouragement to low cost production and a deterrent to high cost production is certainly an advantage. Review of area cost data should be easier than

[584]

examining the incurrence of prudent production costs, perhaps on a field by field, or even a reservoir by reservoir basis. Additionally, it would appear that pipeline production costs have been above the costs of other production when compared on the basis of some common denominators or common allocation method. Under cost-of-service regulations, pipelines have been able to pass these costs on to the consumers. applying area rates to pipeline production in the future would give advance notice of a general ceiling for gas.

The high costs of some pipelines may be largely attributed to their purchasing of more highly developed or "proven" properties than those of independent producers or to their lower rates of take from their own production. Establishing the same basic cost standard for pipelines as independent producers should tend to create greater incentive for the pipelines to operate their production properties efficiently and penalize inefficient operation. It should create disincentive for pipelines to pay higher prices for properties as compared with the purchase of less expensive reserves or production from independent producers. Thus, my recommendation should eliminate situations where lease sales are made at high costs to pipelines to circumvent effective producer rate regulation.

* * *

[619]

Q. Could these differences in the purposes and operational production activities result in different costs for pipeline produced gas as compared with independent producers' produced gas? A. Yes. As I have just testified this could be largely due to pipelines' higher lease acquisition costs resulting from their purchases of more developed, less risky to develop properties, and due to their lower depletion rates. An indication of this may be expressed in Exhibit No. 5 (A.F.B.-1) at Schedule 6, Sheet 1. This sche-

[619]

dule shows the ratios of cash production expenses to the monetary value of the lease products are very close when a comparison between the various groups is made. However, the production expenses *including* the current provision for depreciation, depletion and amortization (DDA) reveals that they are higher for the pipelines. This shows that the pipelines' investment per Mcf of reserves may be much higher than that of other groups.

[620]

These higher unit DDA production costs for the year 1962 were also reflected in witness Bass' Docket Nos. AR64 1 and AR64-2 Exhibit No. 54-J, Schedule No. 1. This exhibit, based on the all area questionnaire, reflects the Continental U.S. composite production costs of the same 15 companies which are termed AAQ companies in Exhibit No. 5 (A.F.B.-1) presented in this proceeding. Witness Bass' Exhibit No. 53-J in the AR64-1 and AR64-2 proceedings at Schedule No. 1 shows the composite Continental U.S. production costs for the companies which are the same companies (AAQ companies) whose data are reflected in witness Bass' Exhibit No. 5 (A.F.B.-1) in these proceedings. These U.S. data reveal a unit DDA cost for the gas leases of 4.0¢ per Mcf for the pipeline group and 2.4¢ per Mcf for the combined independent producers and pipeline affiliate group.

Q. Did the functional and cost differences which you have mentioned influence you to recommend modified area rates for Phase I? A. Yes. Some of the producing pipelines who are respondents to this proceeding expectedly will recommend area rates for pipeline production on the premise that pipeline and independent producer production activities are the same. Of course, if their position is based only on the premise that produc-

[621]

tion is production, they are undoubtedly correct.

However, after carefully studying the testimony and exhibits of other staff witnesses in this case, I have concluded that there are significant differences in the purposes, operations and costs as between pipeline and independent producer operations. Therefore, while I agree that the Examiner and Commission should adopt area rates in Phase I for pricing pipeline produced gas, I think that those rates, or any other regulatory approach adopted, should be carefully tailored to the factual situation of pipeline producers. I fully agree with Dr. Shaffner's observation that since pipeline regulation is a presently established fact, there is no immediate urgency to establish an entirely different mode of rate regulation for pipeline produced gas. Thus, the Examiner and Commission have an opportunity to tailor their experience with both area rates and pipeline regulation to find the optimal regulatory method to apply to pipeline production.

Q. Are the modifications to area rates for rate of return and income taxes proposed by Dr. Shaffner an integral part of your recommendation? A. Yes. As testified to by Dr. Shaffner, the necessary return (and income taxes which are based on return) is largely relatable to over-all company factors. As Dr. Shaffner explained, because, of the integrated

[622]

nature of pipelines' transmission and production activities, producing pipelines can finance their over-all company activities, including their production, more cheaply than producers. Thus, given the pipelines' heavy "leverage", awarding pipelines the same over-all area rate of return on *their* production could in some instances yield them above a 30 percent rate of return on equity investment. Because each individual pipeline's necessary return is individual to it and not closely related to its cost of finding and producing gas,

[622]

it is proper to allow each pipeline the rate of return found appropriate to it. The matter of an income tax allowance is similarly peculiar to individual companies. Tax loss spill-overs from the production function should in the future, as now, be utilized to reduce the tax liability of the transmission function.

Q. If the producer area rate is applied to pipeline production, would that impute an "actual taxes paid" standare to production? A. No. This is because, while the producer rate in *Permian* did not allow any allowance for Federal income taxes, that area rate did not consider the tax losses flowing from the production function over and above those needed to eliminate taxes on the production function.

Q. Assuming that this is the case, would it not be contrary to the theory of area rates to take into effect these additional tax losses?

[623]

A. As I understand it, the doctrine of actual taxes paid prohibits the Commission from allowing consumer charges for an expense which doesn't exist. To allow such charges is merely to allow a forced consumer contribution of additional capital to the company for the benefit of shareholders. Since return and tax expense are interrelated, I think these items should be determined with regard to the individual company.

Your question answers that if the Commission decides to adopt some sort of area or incentive pricing, it should make no adjustment to differences between pipelines and producers or among pipelines themselves. I see no necessity for such conceptual rigidity. Regardless of what is done to producers' rates, the Commission knows from past cases that tax losses do exist on pipeline production and has been giving them effect. I see no reason for it to change this policy merely because it adopts area pricing.

* * *

[629]

In considering the proper regulatory treatment to be given to sales by pipeline affiliates, I realized that (to varying degrees) affiliates might have certain attributes of pipeline producing departments and other attributes of independent producers. From witness Bass' testimony and exhibits in this proceeding and the *Hugoton-Anadarko-Texas Gulf Coast Area Rate Hearings*, Docket Nos. AR64-1 and AR64-2, I concluded that the affiliates' overall costs of producing gas are not significantly different from those of independent producers. However, it does appear that the operations of affiliates are influenced by their related pipeline companies. Thus, for example, from witness Zabel's Exhibit 6 (VHZ-1), p. 4, I noticed that Group 3 companies (on-system affiliates) have lower reserve-production ratios than those of independent producers. That this is less true for Group 4 companies (off-system affiliates) is shown by Exhibit 6 (VHZ-1), p.5. From a study of Mr. Zabel's testimony and exhibits, I was able to conclude that pipeline affiliates have been depleting their reserves at a faster rate than independent producers. These factors indicated to me that pipelines and their affiliates had been able to integrate their operations sufficiently to allow affiliates to produce their reserves more efficiently than independent producers. Furthermore, affiliates' exploratory efforts have apparently

[630]

been better keyed to demand than those of independent producers. Therefore, affiliates' investment in reserves before they were needed has been lower than independent producers' investment.

Q. How do these facts influence your rate recommendations with regard to pipeline affiliates? A. If both pipeline production and independent producers production are to be regulated on an area basis, then, even more so, pipeline affiliates should receive the same treatment as independent producers. However, my review of the facts has convinced

[630]

me of reasons for applying such treatment to pipeline affiliate producers. Since affiliate production and finding costs are comparable to those of independent producers, application of area rate pricing to them would not seen inappropriate. Also, as already stated, adoption of area rates for both pipelines and affiliates would tend to reduce the advantages of "spin-offs."

Q. Why did you decide to recommend application of the pipeline area rate for on-system affiliate sales, but the producer area rate for off-system affiliate sales? A. As I have testified, pipeline affiliates have attributes of both independent producers and of pipeline production departments. It appeared to me that in choosing between the two area rates, the best possible course would be to apply the producer area rate in circumstances when the affiliate

[631]

was functioning more akin to an independent producer and the pipeline rate when it was functioning with its affiliated pipeline as an integrated entity. Thus, when the producer is selling independently of its affiliated pipeline company, it would be treated as any other producer; when it is selling to its affiliate, it would be treated as a single operation. Such regulatory treatment gives recognition to the advantages of affiliation which I have just discussed. These advantages result in more efficient operations due to the affiliated company being able to mesh production with pipeline demand. Parenthetically, I would remark, as Dr. Shaffner has pointed out, it is just such advantages which would result in reduced financing costs for integrated entities.

* * *

[637]

TESTIMONY OF J. G. DICKINSON, JR.

Q. Will you please state your name and where you reside? A. J. G. Dickinson, Jr. I live in Amarillo, Texas.

Q. What is your present occupation? A. I am a consultant in matters relating to oil and gas. I am a registered professional engineer in Texas.

Q. For whom are you appearing in this proceeding? A. I am appearing as a witness for the Pipeline Production Group.

Q. What is your educational and professional background? A. I graduated from the University of Alabama in 1917 in electrical engineering and then studied at Massachusetts Institute of Technology until entering the Air Corps of the United States Army. From 1919 until 1930, I was an employee of Cities Service Gas Company and its predecessor, Empire Gas and Fuel Company. During this period my duties involved exploration, development and production of oil; first as a junior engineer and ultimately as production superintendent of various divisions. I participated in the initial project involving application of electric power to oil

[638]

field operations in the area and also in one of the first gas repressuring projects. In 1930, I undertook my first assignment directly involving the production activity of a transmission system.

Q. Will you briefly describe this phase of your experience? A. My job was that of Manager of Production for Continental Construction Company which was formed to assemble gas supplies and to construct a pipeline from the Texas Panhandle area to the metropolitan Chicago area. Upon completion of the pipeline it was succeeded by Natural Gas Pipeline Company of America, by whom I was employed for many years.

Q. What duties did you perform as Manager of production in the initial stages of that project? A. I had the primary responsibiility for obtaining and developing gas supplies of this new transmission system. This involved participation in negotiations for gas supply, and supervision and direction of the Amarillo headquarters which was established to handle the production operations. I served in this capacity until 1950 having responsibility during this period for the Company's gas supply matters. In 1950, I became Vice President of Production of Natural Gas Pipeline Company of America, and an officer of Texas-Illinois Natural Gas

[639]

Pipeline Company, which constructed a pipeline from the Texas Gulf Coast to Chicago. I also served as Vice President of Production of Texoma Production Company, a producing subsidiary of Natural Gas Pipeline Company of America.

Q. Were these three companies engaged in gas production activities? A. Natural Gas Pipeline Company of America was extensively engaged in drilling and other production activities from the outset of its existence in about 1930. Texoma was similarly engaged until 1950 when it merged into the parent company. Texas-Illinois, on the other hand, which came into being in 1950 purchased its gas supplies from other producers.

Q. Have you had any other experience in directing exploration, development and production operations? A. I was Vice President of Production of Peoples Production Company, which was a joint effort with Sinclair Oil & Gas Company, Standard Oil Company of Ohio and El Paso Natural Gas Company, and engaged in acquiring leases and exploratory activity off-shore in the Gulf of Mexico. Also I was Vice President of Production of Natural Gas Storage Company of Illinois, which developed the first successful large gas storage reservoir aquifer which had no native oil or gas

[640]

originally, and is now the largest underground gas storage operation in existence.

Q. You have stated that you were in charge of the production departments of the companies with which you were associated. Were you also engaged in transmission activities? A. Not except by way of supporting the transmission and marketing departments. Production departments of pipeline companies are separate organizations, frequently located a considerable distance from the operating organization. But, they maintain familiarity with the current and anticipated conditions relating to the other departments. This

enables the production department to assist in providing additional supplies when needed, and in cutting back deliveries to the extent necessary to meet market and flow conditions.

Q. When did you relinquish your duties with the organizations which you have described? A. In 1959 I resigned as Senior Vice President of all of those companies. In the following year, I resumed active participation in the industry and have been engaged in oil and gas property management, appraisal work, estate management and other consulting assignments.

Q. Are you generally familiar with the techniques used in exploratory, developmental and production work

[641]

by oil and gas companies, and with the methods which are used in this industry? A. Yes, sir, I have been continuously engaged in this work for more than forty years, during which I have had extensive experience in supervising the operations of pipeline producers and working closely with independent producers. Based on this experience I can state that these classifications are the same in technology and methodology.

Q. When you commenced your work in the producing industry, was there a substantial number of pipeline companies which owned or controlled portions of their gas supplies? A. Yes, I believe that the pipeline companies which were in operation during that period acquired part or all of their own supply and engaged in substantial production activities.

Q. Can you identify those pipeline companies? A. There were nine transmission companies in operation in the Texas Panhandle area which furnished the supply for the early long distance gas pipelines. Perhaps the earliest was Northern Texas Utilities Company, which commenced transporting gas in 1926 to markets in the area of Wichita Falls. Shortly thereafter, Lone Star Gas Company commenced operation of a 200 mile line

[642]

to Fort Worth and Dallas. The South Plains Pipe Line Company constructed and operated a somewhat lònger line to Amarillo and the South Plains; this transmission line is now owned by Pioneer Natural Gas Company. Cities Service Gas Pipe Line Company, a predecessor of Citis Service Gas Company installed the first 20-inch long distance transmission line in the area extending some 400 miles to Kansas City, Missouri. In the same year, 1928, the Canadian River Gas Company and Colorado Interstate Gas Company began deliveries to the Denver area and the Consolidated Gas Utilities Company began transporting gas to markets in Oklahoma and Kansas. In addition, three of the largest existing pipeline companies went into operation with 24-inch lines in 1931 and 1932. Panhandle Eastern Pipe Line Company built its 1100 mile line into Illinois and Indiana. Also, Northern Gas and Pipe Line Company, which is now Northern Natural Gas Company built a line into the Omaha market, and Natural Gas Pipeline Company of America's original transmission system was installed serving markets in Nebraska, Iowa and Illinois.

Q. Did the pipeline companies which you have just described acquire leases and undertake production activities in the early 1930's? A. Yes, these pipeline companies obtained large

[643]

leasehold interests and produced substantial volumes of gas.

Q. In the period when the pipeline companies were developing their transmission systems, did they obtain gas supplies under purchase contracts, or was all of their supply from company-owned reserves? A. The pipeline companies purchased substantial amounts of gas from independent producers but, generally speaking, pipeline ownership extended to a large portion of the volumes which the pipeline company transported and sold.

Q. Are you familiar with any marked change in this pattern? A. Yes, I am familiar with the fact that the pipeline companies, at least those operating interstate, have become increasingly dependent upon purchased gas instead of supplies which they find, develop and produce from their own reserves. Some activity in recent years has involved the purchase of large packages of gas which the independent producers have found and partially developed. I see nothing essentially wrong with this but, of course, it does not really increase supplies since it involves a transfer from others. My discussion of pipeline production activity relates also to the exploration, development and production of reserves in

[644]

a conventional manner.

Q. Under present day conditions, are pipeline companies capable of engaging in exploration, development and production in the conventional manner? A. This is dependent upon the extent to which they have maintained their organizations, and particularly their know-how and familiarity with geological, geophysical and other data which is absolutely essential to successful large-scale operations in the producing industry. Of course, some of the pipeline producers just as some of the independent producers, will be less successful than others for a variety of reasons. But, there is no reason whatever that prudent pipeline producers if properly staffed and operating under the same level of inducement as other producers, cannot achieve comparable results.

Q. Are there any substantial differences in the techniques and methods available to pipeline producers as compared with other producers? A. As far as techniques and methods available, there are no differences whatever. In a going organization, pipeline producers are able to follow the same methods, use the same tools, and apply the same techniques.

Q. Are all of these factors completely uniform or standardized?

[645]

A. Many of them are. Others are not, but these techniques and services are just as available to pipeline and affiliated producers as to independent producers. For example, assuming qualified and experienced company personnel, and given the intensive preparatory background and accumulation of data which I have referred to, the initial affirmative step in each project is the obtaining of the mineral lease. This is an item in which there can be variations in cost and other factors among the available leases but there is nothing inherent in the producing industry which precludes any class of producers from acquiring any particular lease.

Q. How are the leases obtained? A. They may be available directly from the fee owner, from a lease broker, from a producer which acquired the lease originally but does not seek to drill on it, or in some instances, from the government. All of these sources are available to all types of producers, and no segment of the industry has any inherent advantage over the other.

Q. What would be the next stage of activity by the producer with respect to leasehold interests which it acquires? A. The well established producers would undertake geophysical testing and evaluation in their own organiza-

[646]

tions. Consultants and service companies are also available to perform technical work for independent producers and pipeline producers on the same basis. Similarly, both are able to analyze and interpret the results through qualified company personnel. Therefore, there would be no differences in this step in the process.

Q. Does this conclusion also apply with respect to the actual drilling operations? A. Neither the independent producer nor other producers actually perform the drilling as a general rule. There are many excellent drilling contractors who are willing to undertake this work without regard to whether the operator is a pipeline producer, affiliated producer or independent producer.

Q. Do the drilling contractors arrange for the procurement of materials used in connection with the well? A. Not in all cases, but again these materials are as readily available to one class of producers as to another, and at the same cost.

Q. What other steps would be needed? A. One of the next steps would be the logging of the well by electric log. This work, which is performed by service companies is available to all producers at

[647]

standardized costs.

Q. Is the interpretation of the logs performed by the operator or by the service company? A. There are firms which are available to interpret the logs, but a well established operator would have qualified personnel in its own organization upon whom it would normally rely. The next steps in the process, however, would be handled by suppliers and service companies. These would include the cementing of the casing which would be done under contract, the perforating of the casing which would also be done by contract and the clean-out operations, also handled by contracts with companies which perform such services for all producers. The setting of separators and tanks, if needed, is readily available at established prices. All of these costs are comparable for various types of producers and it follows that the cost of the entire operation for a particular well would not be affected materially by the classification of the operator.

Q. Are there any other factors which would tend to insure comparability among producer classifications for those activities? A. Many of the operations are conducted jointly among two or more producers. Under these circumstances, there would be not only comparability but the items would be

[648]

exactly the same.

Q. Would this conclusion apply generally to activities other than exploratory work? A. Yes, I think it would apply to all phases of exploration, development and production, still assuming that the organizations of the various producers are properly staffed and actively engaged in these operations.

Q. From your knowledge of the industry, are the pipeline and affiliated producers in that position at the present time? A. Many of them are because they have been actively engaged in these operations. Others are partially dormant, more or less in a stand-by condition. And, some of the pipeline producers are at various points between those two extremes.

Q. Why do you place emphasis on the maintaining of an active organization in order to achieve comparable results? A. Principally because of the substantial number of steps which must be taken in establishing a qualified and competent organization and in actually conducting successful exploratory operations.

Q. What are the necessary steps? A. The first requirement is the establishment of a geological department and staff which would then undertake

[649]

planning and evaluation. The next step would be to determine the areas which appear more promising and of these, to select the ones which would fit best in the company's plans. It is then necessary to establish a land and lease department and to accumulate files and records which would be used in acquiring leases. Then there must be extensive studies as to the areas in which acreage is available for leasing. One of the most important steps in the work which must be done is selecting the most favorable prospects for leasing. This work is performed by the geology department, but since it involves budgetary and policy consid-

erations, managerial decisions are also an essential part of the process. The next step is the effort to acquire leases from the selected prospects on the most favorable terms. A factor affecting the time which is required for this step is the producer's general preference for acquiring leases in large blocks.

Q. What is the next step? A. Before any drilling is undertaken, further intensive geological and geophysical work may be needed. This will result in selection of drilling sites from among the possibilities, and a recommendation of the depth to be tested. One factor to be considered is the type of hydrocarbon which is being sought. This, of course,

[650]

is a policy consideration which is governed in part by the relative inducements of each product at a given time, but it is also affected by market factors and by the other types of operations in which the company is engaged such as extraction, refining, transmission, and so forth. It is then necessary to determine whether the prospect is to be tested by the company alone, or in conjunction with other producers. Frequently extensive title work may be required before drilling could be safely commenced. There are regulatory steps also, where unitization is appropriate. All of these steps are time-consuming, and the period of time and effort devoted to their accomplishment can materially affect the degree of success which will be achieved. The actual drilling is perhaps the least difficult and time-consuming aspect of the program unless subsurface or mechanical problems are encountered. But, with each new well, and from developments observable in existing wells, reevaluation is frequently required, and it may occur at any stage in the process. I have already described various steps which are taken during the drilling process. Finally, the conduct of any continuing production business, of course, requires production and operating personnel which must also be provided.

[650]

Q. What period of time would be required for a pipeline

[651]

company which has the financial ability, to accomplish the steps which you have outlined? A. This is a rather long-range undertaking. In order to be in a position to obtain significant volumes of production it would require several years. In order to achieve an efficient level of performance, I believe that six to eight years would be required. These periods would be applicable to pipeline companies and my estimates take into consideration the fact that the pipeline companies have some knowledge of production by reason of their gas purchase activities. Of course, such an undertaking would require continued interest on the part of the management of the pipeline company and this in turn would be affected by the supply picture and market conditions, including price.

Q. Given satisfactory conditions in these regards, are the pipeline companies capable of achieving the steps which you have outlined? A. Yes, they are. And they would have the same range of potentiality for successful operations as any other well-established producer. This is demonstrated by the actual performance of the pipeline companies. Many of them conducted substantial exploratory, developmental and production operations, and some of them still do. Others are at various stages of dormancy as I have

[652]

previously indicated. The current production capabilities of the various pipeline companies is affected by their level of operations, which in turn is affected by the regulatory treatment which they expect to receive.

Q. Based on your experience, are the pipeline and affiliated producers subject to the same regulatory treatment as the independent producers? A. They are in each state at the production end, but there has been quite a difference in the past insofar as rate treatment at the federal level is concerned.

Q. Would withdrawal of the production activities by the existing pipeline producers preclude their re-entry should future conditions ultimately make this either necessary or desirable? A. No, this would not be impossible but it would be quite difficult, even for a single company. It would also be most unfortunate, because of the serious waste which would occur if the present capabilities of the pipeline companies and their affiliates are permitted to deteriorate because of lack of inducement. There is another point to consider in this connection; we have been assuming throughout this discussion the availability of funds. Production operations should be maintained at least in large part, through revenues received from existing production. It requires a very substantial

[653]

effort simply to replace the production from which these revenues are derived. Thus, inactivity in exploration and development must in due course reduce the production volumes from existing reserves, thereby decreasing the ability to generate revenues from this source. The problem becomes more difficult, of course, as the inactivity becomes more widespread. If, in addition to the deterioration of the present capabilities of the pipeline and affiliated producers, their lesser activity seriously reduces the level of productive capacity of pipelines and affiliates, the substantial initial investment which would be required for the industry upon re-entry leads me to question whether the over-all capabilities could ever be restored, regardless of inducement or need. On the other hand, given the inducement which is needed, the gas pipeline companies can make a significant contribution toward improving the overall ability of the industry to supply production for the ever expanding market.

[654]

TESTIMONY OF W. P. ANDERSON

Q. Will you please state your name and business address. A. W. P. Anderson, 3444 Broadway, Kansas City, Missouri.

Q. What is your present position? A. I am Manager, Rates and Economics, of Panhandle Eastern Pipe Line Company. I am appearing in this proceeding for the Pipeline Production Group.

* * *

[656]

Q. Have the studies which underlie your presentation been prepared in exhibit form? A. Yes. These studies reflected in Exhibits 22 (WPA-1) to 34 (WPA-13) have previously been distributed to the parties to this proceeding.

Q. With reference to the exhibits which reflect comparability studies, will you please explain the aspects of the problem which you have examined? A. We have examined a number of significant aspects of comparability among Pipeline Producers, Affiliated Producers and Independent Producers. My own work has been concerned with the extent to which these classifications have experienced similar performance in exploratory and developmental abilities and in cost incurrence. We found that all three segments of the producing industry were essentially similar insofar as the basic factors underlying their exploration, development and production activies were concerned.

* * *

[658]

Q. What study have you made regarding the comparative abilities of the three segments of the producing industry to explore for and develop natural gas? A. We have prepared comparative studies of the success ratios of these groups, both in exploratory drilling and also in developmental drilling.

Q. Will you please describe your study of exploratory well drilling? A. This study is contained in Exhibit 23 (WPA-2), and sets forth the success ratios for exploratory drilling of each of the three classifications, Pipeline Producers, Affiliated Producers and Independent Producers for each of the years 1955-1962, the period covered by the All-Area Questionnaire.

Q. Will you briefly summarize the results of this study? A. The success ratios in exploratory drilling among the three segments of the producer industry, as reflected in the All-Area

[659]

Questionnaire are as follows:

Pipeline Producers	31.7%
Affiliated Producers	30.6%
Independent Producers	29.5%

Q. What difference, if any, would the exclusion of the Appalachian companies make in this result as reflected in your second summary? A. The exclusion of the Appalachian companies changed the success ratio of the Pipeline Producers from 31.7% to 30.6%, which in my judgment is not a material change. It means that the Appalachian companies had essentially the same success ratio as the other Pipeline Producers and that all segments of the producing industry were within very close tolerance.

Q. Have you prepared a study of the developmental well drilling for the three segments of the producing industry? A. Yes, I have. The success ratios for developmental drilling are reflected in Exhibit 24 (WPA-3).

Q. Will you please explain Exhibit 24 (WPA-3) dealing with developmental well drilling success ratios? A. The same method was used and the same data was shown as those which I have described with respect to the preceding exhibit concerning exploratory success ratios. The results also show no essential difference in comparability among

[659]

the three segments. In terms of percentages, the developmental success ratios for the

[660]

eight-year period are as follows:

Pipeline Producers ·	84.5%
Affiliated Producers	85.4%
Independent Producers	87.5%

Q. What effect, if any, would the exclusion of the Appalachian producers have upon the success ratios? A. The exclusion of the Appalachian companies would change the Pipeline Producer developmental success ratio from 84.5% to 83.1% which again, is not a material change.

* * *

[664]

Q. Will you please describe the balance of Exhibit 28 (WPA-7). A. The first section of this exhibit contains the exploration and development curve and also the transmission curve for each of the Pipeline Producers. This data was taken from the two tabulations which I have just described, and reflects the trends from 1955 through 1962 for each company. The most inactive Pipeline Producers, from the standpoint of exploration and development, are shown together on the last page of this section. The exploration and development expenditures for these Pipeline Producers somewhat exaggerates their activity, because of the inclusion of the amounts which were written off for abandoned leases.

Q. Will you now proceed to describe the recent trend data regarding Pipeline Producers' reserve and production activities as compared with the Independent Producers? A. Page 1 of Exhibit 29 (WPA-8) is a reproduction of the data published by the ACA Committee on Natural Gas Reserves, showing total United States gas reserves for the years 1955-1966. The second page of

[665]

the exhibit is simply a reporduction of the reserve production ratio curve, reflecting data from the same source. From 1955 to 1958 there was virtually no net change in the years of life index but for the following eight years there has been a significant decline. These data reflect an increase of 36,571,013 MMcf in proven reserves over the period covered from 1958 through 1966 after allowing for the aggregate volumes produced during that period.

Q. Have you prepared an exhibit reflecting the proven reserves of the Pipeline Producers for this same period? A. Yes, Exhibit 30 (WPA-9) shows the volume of pipeline-owned reserves of the Pipeline Producers at the end of 1966, and also at the end of 1958, so that the increase or decrease over the eight-year period can be determined. This data is taken from the Form 2 reports of the pipeline companies.

Q. Will you please summarize the results of this study? A. The study shows that each of the Pipeline Producers with large company-owned reserves suffered a major decline in the level of its company-owned reserves over this recent eight-year period. The net reduction for these fourteen Pipeline Producers was 8,038,235 MMcf. It may be observed that the volumetric decline and also the percentage decline is largest in the case of the pipeline companies owning the largest reserves.

Q. Have you ascertained whether these Pipeline Producers experienced

[666]

similar declines in their reserves attributable to gas purchase contract? A. No, they have increased their reserves under gas purchase contract while their owned reserves were being depleted. This is shown on Exhibit 31 (WPA-10). Between the end of 1958 and 1966, the total gas reserves committed to these Pipeline Producers exclusive of amounts which they had committed to each other, increased by 35,768,847

MMcf, but the portion attributable to company-owned reserves was decreased by 8,038,235 MMcf. This exhibit also shows the annual decrease in company-owned gas reserves of the Pipeline Producers during each of years from 1955 through 1966.

Q. What portion of their committed reserves did these companies own at the end of the period? A. They owned only 13% of their gas reserves at the end of 1966, compared to their 25% ownership level only eight years before, as shown on Exhibit 31 (WPA-10).

Q. Have you prepared a study reflecting the trends in gas and oil production for Pipeline Producers compared with Affiliated Producers and Independent Producers? A. Yes, I have. Exhibit 32 (WPA-11) sets forth the lease production volumes of each of these three segments of the producing industry for each year 1955-1962.

Q. Will you please describe Exhibit 32 (WPA-11)?

[667]

A. This exhibit shows the change in the yearly volume of gas produced by the Pipeline Producers, Affiliated Producers and Independent Producers. It also shows similar data for oil production by the three segments. The Pipeline Producers' increase in natural gas production over the eight-year period amounted to only 18% as compared to an increase in production by the Independent Producers of 68%. On the other hand, the Pipeline Producers increased their oil production over this period by 122% while the Independent Producers were increasing their oil production by only 27%. The underlying data for this study was obtained from the responses to the Commission's All-Area Questionnaire.

* * *

[669]

TESTIMONY OF JAMES C. JONES
(Docket No. RP66-24)
* * *

[670]

Q. Have you been a witness in area rate proceedings? A. Yes. I testified in the Hugoton-Anadario area rate proceeding. Docket No. AR64-1.

Q. What studies have you prepared for presentation in the Pipeline Production Area Rate proceeding? A. I have made a study of the extent to which Pipeline Producers and Affiliated Producers have joint ownership of producing properties with other producers. The degree of joint ownership is indicative of the extent to which Pipeline Producers, Affiliated Producers and Independent Producers would have comparable or identical characteristics. I then prepared a study as to the cost of new non-associated gas to be developed by pipeline producers from future production, in order to compare the cost of future pipeline produced gas with the cost of all new non-associated gas. Having ascertained that the unit cost of new gas for pipeline producers does not differ substantially from the cost of new gas for the producing industry as a whole, I then examined the data available from Commission sources in order to determine whether there is the same wide dispersion among the various producing companies in each of the segments of the producing industry.

Q. What results are indicated by the studies which you have just described? A. These studies, which I shall explain in greater detail, demonstrate

[671]

that there is a substantial joint ownership among Pipeline Producers, Affiliated Producers and other producers, that the cost of future pipeline-owned production is substantially the same as the cost of future production for the producing

industry as a whole, and that there is a wide dispersion among the companies which produce natural gas, whether they be Pipeline Producers, Affiliated Producers or Independent Producers. These considerable disparities reflect the type of conditions previously described by the Commission in connection with its determination to use the area method of group pricing for produced gas.

Q. Have you prepared exhibits reflecting the results which you have just described? A. Yes, I have.

Q. Turning first to your exhibit regarding joint ownership, will you explain the method by which it was prepared. A. In accordance with the Examiner's ruling, the Pipeline Production Group circulated a supplemental questionnaire at the same time the Staff Form 50 questionnaire was circulated to the respondents in this proceeding. Although no information was made available by two or three of the larger Affiliated Producers, we obtained data from 26 Pipeline Producers and Affiliated Producers regarding their joint ownership with other producers of gas, gas condensate, oil and other wells. From this data, we determined the number of joint interest wells and the total number of wells as of December 31, 1962, for the Pipeline Producers and Affiliated Producers. Although the data reflected in my Exhibit 35 (JCJ-1) demonstrates

[672]

that there is a great deal of joint ownership of wells among Pipeline Producers, Affiliated Producers and other producers, these results understate the total scope of the joint ownership, which would be increased, of course, with the addition of the joint interest wells of the Affiliated Producers which did not submit responses.

Q. Will you briefly summarize the results reflected on your Exhibit 35 (JCJ-1) as to joint ownership? A. At the end of 1962 there were 6798 joint wells in which these Pipeline Producers and Affiliated Producers had varying degrees of working interest, but less than complete ownership of the working interest. Exclusive of the Appalachian

area, 49% of the wells in which these companies had working interest were jointly owned with others. The Pipeline Producers in the Appalachian area represent a significant exception since less than 2% of their wells are jointly owned.

Q. In making the cost comparison for future gas production which you have described, did you use the method prescribed by the Commission in the Permian Area proceeding, Docket No. AR61-1? A. Yes, I did. The results of the comparison are reflected on Exhibit 36 (JCJ-2).

Q. Will you please describe this exhibit? A. Exhibit 36 (JCJ-2) is an analysis of the cost of producing new non-associated gas to be obtained in the future for the Pipeline Producers and the comparison between the cost of the Pipeline Producers for their future gas with the cost of such gas for the producing industry.

[673]

Q. Have you made the computations of the unit costs which are to be used for this comparison? A. I made the computations of the unit cost for Pipeline Producers and then compared the results of that study with the presentations of the major participants in the most recent area proceeding involving the computation of national cost for new gas. I have included in the exhibit the results of the Commission's determination of this same item in the Permian proceeding.

Q. What data were used for determining the cost of new gas for Pipeline Producers? A. Basically, the data were obtained from the All-Area Questionnaire responses filed by the Pipeline Producers, except for the reserve data which was obtained from reports submitted by the Pipeline Producers to the Commission.

Q. What unit cost did you derive for the Pipeline Producers as to future gas on a continental basis? A. As shown on Exhibit 36 (JCJ-2), the unit cost for Pipeline Producers is 17.35 ¢ per Mcf, which may be compared with the 16.62¢ per Mcf mean unit cost for the industry as a whole.

[674]

Q. Does the substantial similarity of cost of new gas for the Pipeline Producers with that of the producing industry as a whole indicate that individual companies will have relatively slight variation in the cost of the gas which they produce? A. No, it does not. The figures which I have just discussed are group composites. There will be wide variations in the costs for individual companies. I have analyzed the variations actually

[674]

experienced by all of the producers which submitted usable responses to the All-Area Questionnaire and the results of this analysis are reflected on my Exhibit 37 (JCJ-3). This exhibit demonstrates that the 86 producers from all classifications have a variation of from 1.83¢ per Mcf to 111.84¢ per Mcf in the array of unit costs.

Q. What is the source of the form which you have used in preparing this array? A. It has been prepared in the general form in which the arrays were presented by the Commission Staff in the Southern Louisiana Area Rate Proceeding, subsequent to the Commission's orders of July 13, 1964 and August 27, 1964, in which the Commission expressed the view that arrays of this type would be useful in portraying the dispersion of costs. Similar material was also presented in the Hugoton-Anadarko Area Rate Proceeding.

* * *

[675]

TESTIMONY OF M. J. PECK

Q. Will you please state your name and where you reside? A. My name is Merton J. Peck. I live in New Haven, Connecticut.

Q. Will you please state your educational background? A. I graduated from Oberlin College in 1949 with a degree in economics and then began graduate studies in economics at Harvard University. I received my M.A. degree in 1951 and my Ph.D. degree in 1954.

Q. What is your professional experience? A. In 1954, I commenced teaching classes in economics and regulatory problems at Harvard College, then at the University of Michigan, the Harvard Business School, and, since the fall of 1963, at Yale University. During 1961 and 1962, I served as Director of Systems Analysis in the Comptroller's Section of the Office of the Secretary of Defense.

Q. What have you had published in the field of economics? A. My publications, as my teaching, have been in the field of market organization and public policy—the branch of economics that deals with competitive and regulatory problems. They include a book on competition in the

[676]

aluminum industry and coauthorship of a book on public policy in the transportation industries, and the coauthorship of another on government policy in the defense industries.

Q. Have you given consideration to the question of regulatory treatment of natural gas produced by pipeline companies and affiliates? A. Yes. I originally considered this matter in connection with the Hugoton-Anadarko Area Rate Proceeding in which the Commission had planned to resolve the issue as to the proper method of rate regulation of pipeline producers and affiliated producers. During the course of the hearings, the Commission severed that subject from the general area proceeding and initiated the present proceeding which is devoted, in the present phase, to the consideration of appropriate rate treatment for pipeline producers and affiliated producers with respect to natural gas produced from leases acquired subsequent to the time the Commission issues its order resolving the first phase of the proceeding. My testimony deals with the regulatory treatment of pipeline production of natural gas as just defined.

Q. What was the scope and subject of your inquiry in connection with the present proceeding? A. I have applied my general skills as a market organization economist to two

[676]

questions: (1) is there a significant economic difference between the natural gas production

[677]

activities of pipeline producers (including separate corporations affiliated with pipeline companies) and the independent producers which would justify distinct regulatory policies for the production activities of these two groups; and (2) what would be the effects of individual company cost of service regulation of the production activities of pipeline producers. I have made no empirical investigations personally, but rather the statistical materials were gathered by other witnesses who are sponsoring these exhibits. My testimony is directed at the economic significancies of their exhibits.

Q. Are you making any specific recommendation at this time as to the rate making method which should be used for natural gas production? A. No, I have assumed that the alternative to individual company cost-of-service rate making is some form of group pricing, but I have not examined the various alternatives in the general category of the group-pricing method of rate regulation.

Q. Are you making any specific recommendation at this time as to the rate level or rate design which should be established for gas produced by pipeline companies or independent producers?

[678]

A. No, my investigations did not deal with rate level or rate design. I have assumed, however, that both the rate level or rate design which will be adopted will be designed to provide sufficient economic incentive for efficient and adequate exploration, development and production of natural gas.

Q. Let me turn now to your first question: the economic differences between the two classes of producers—the pipeline producers and the independent producers—that might

justify a difference in regulation. What is the economic framework by which an economist considers this question? A. Methods of price regulation ought to be based upon the supply conditions of the producers since the objective of regulation is to set a price that will bring forth an adequate and efficient supply of the regulated service or commodity without leaving an unneeded producers' surplus. Differences in regulatory methods for two classes of producers would be justified to an economist when the two classes had difference in their conditions of supply or, more technically, when the slope or level of the supply function or curve relating the price and quantity offered differs between the two groups of producers.

[679]

Q. How does an economist determine whether the supply conditions of two classes of producers differ or are substantially similar? A. The supply function or curve often cannot be observed directly. Hence it is necessary to go behind the supply function and consider the conditions that determine the willingness of two groups of producers to supply a commodity at various prices. Among the conditions of supply to be considered are the following: (1) technology, (2) risk and uncertainty, (3) costs and (4) source of investment funds. With respect to the first three factors, other witnesses sponsored by the Pipeline Production Group provided the data, but I have examined this material, which forms the basis for my conclusions. With respect to the source of funds, other witnesses for the Pipeline Production Group will discuss this factor.

Q. Which role does technological similarity have in creating firms with the same supply conditions? A. Firms with similar technology should have, in general, similar costs and the same technological opportunities. Mr. J. G. Dickinson, Jr. has made a study of the technological methods employed by pipeline producers and other producers. I am relying upon his determination that

[680]

the technology is the same, and to me, as an economist, this demonstrates that the two groups of producers are comparable in this dimension.

Q. You mentioned risk and uncertainty. What is its role in your comparability analysis? A. Risk bearing and uncertainty are a necessary attribute of business activity. In addition to such general risks and uncertainties, natural gas production bears the special uncertainty that the drilling of a well will result in a dry hole. On an industry basis, the established record of the pipeline producers, affiliated producers, and independent producers demonstrates that the incidence of unsuccessful wells is substantially the same for each class. Stated another way, the pipeline producers, affiliated producers, and independent producers have each demonstrated the ability to obtain substantially the same success ratio in both their exploratory and developmental efforts.

Q. Upon what source do you rely for a determination of the success ratio? A. Data on success ratios was obtained from all the responses of companies supplying data to the Commission's All-Area Questionnaire. Mr. W. P. Anderson has assembled this data and he can explain in detail the method which was used to compile these success ratios. In examining

[681]

success ratios, it is important to distinguish between exploratory and development wells since it is apparent that the former by its very nature, will have a lower success ratio. Comparisons of the success ratios of all wells could be greatly influenced by the porportions of exploratory and development wells in the two groups being compared.

Q. Are there exhibits which indicate success ratios? A. Yes. Exhibits 23 (WPA-2) and 24 (WPA-3), sponsored by Mr. Anderson, provide the success ratios for the exploratory and developmental drilling for the eight-year period from

1955 through 1962, the period covered by the Commission's All-Area Questionnaire.

Q. What is shown by the first of these exhibits, Exhibit 23 (WPA-2)? A. Exhibit 23 (WPA-2) demonstrates for the eight-year period as a whole, the success ratio for exploratory wells, as reported by all the companies submitting usable responses to the Questionnaire, was 29.6%. By classification, the success ratios were as follows:

Pipeline Producers	31.7%
Affiliated Producers	30.6%
Independent Producers	29.5%

[682]

The deviation from the overall average by any one group does not exceed 2.2%. To be sure, the small number of wells drilled in any one year by the two smaller groups of producers—pipelines and affiliates—means that their success ratio in any one year can and did deviate significantly from the industry average for that year.

Q. What is shown by the second exhibit, Exhibit 24 (WPA-3)? A. Exhibit 24 (WPA-3) demonstrates that for the eight-year period, the success ratio for developmental wells, as reported by all the companies which submitted usable responses to the Questionnaire was 87.3%. By classification, the success ratios were as follows:

Pipeline Producers	84.5%
Affiliated Producers	85.4%
Independent Producers	87.5%

Q. You have now summarized the similarity of technology, and risk and uncertainty with special reference to exploration and development. Have you examined the indicated cost of pipeline produced gas in relation to the cost of gas to be produced by the producing industry as a whole? A. Yes, but here I rely upon the presentation sponsored by Mr. Jones. His exhibits compare the unit cost of new

[683]

gas, on a continental basis, for the pipeline producers with the unit costs for all natural gas producers as shown in other submissions including the Commission's determination in the Permian Area proceeding. The costs for new non-associated gas for pipeline producers and also for all producers (based on the average value of such estimates as set forth in Mr. Jones' testimony) are as follows:

All Producers	16.62 cents per Mcf
Pipeline Producers	17.35 cents per Mcf

Q. Have you been furnished comparative costs for drilling and equipping wells? A. Yes. Mr. Anderson's studies were made available to me. With respect to drilling and equipping costs, the results can be summarized in terms of the cost per foot of productive wells for the three classes of producers:

Pipeline Producers	\$17.43
Affiliated Producers	\$17.68
Independent Producers	\$17.67

Since drilling costs vary with depth, separate computations were made for each of the seven depth ranges requested in the All-Area Questionnaire. Exhibit 26 (WPA-5), sponsored by Mr. Anderson, and from which the numbers I just cited

[684]

were drawn, provides data for each depth range. As Mr. Anderson's testimony indicates, the cost variations between classes of producers in individual subclassifications by depth range and well type can be accounted for by the small numbers of observations in certain classifications.

These comparisons indicate the similarity of costs incurred by the three segments of the producing industry. To the extent that changes in drilling and equipping costs may occur in the future, they should become generally applicable to all segments of the industry, for the reasons indicated in

Mr. Dickinson's testimony, so that the cost comparability should continue to be relatively close.

Q. On the basis of your analysis of the comparability of technology, risk and cost for pipeline and nonpipeline producers, what conclusion have you reached? A. I would conclude that substantially similar conditions of supply, as I have used this term, are applicable to these groups of producers. In this situation, dissimilar rate making treatment serves to discourage the class of producers which receives the lesser incentive and causes a relative decline in that group's production activity. This follows from the fact that if two groups of business firms have

[685]

similar conditions of supply but they are not given the same incentives and opportunities, there will be a relative decline in this activity by the less favored group.

Q. What is the historical evidence that differences in rate regulation in fact causes difference in relative activity of two groups of producers? A. During the period 1955 to 1962, the pipeline producers have been regulated by the individual company cost of service method. The regulatory method for the independent producers has been less clear cut.

While some cases involving independent producers were initiated on a cost of service basis prior to 1960, this method of regulation was not applied to reduce the rates of independent producers on a system-wide basis. After 1960, the guideline rates, a form of group pricing, was applied. Thus, the regulation of independent producers was in a state of flux during 1955 to 1962 and may have been less than fully effective in the early years. Still the record from 1955 to 1962 yields an indication of the sensitivity of natural gas production to differences in regulatory approach.

The pipeline producers have a declining proportion of both the natural gas volume marketed by the respondents to

[686]

the All-Area Questionnaire and by all sellers. This is indicated by Exhibit 33 (WPA-12), sponsored by Mr. Anderson. In relation to the marketings of all respondents, the pipeline producer respondents declined from 10.6% in 1955 to 7.8% in 1962. In relation to the total of all gas marketed in continental United States, the pipeline producers' share declined from 6.6% in 1955 to 5.2% in 1962. The declining share of the pipeline producers may be contrasted with the share of the independent producers in total marketed gas which increased from 50.4% in 1955 to 56.5% in 1962, or that of the respondent independent producers in all respondents marketed volume which increased from 81.1% in 1955 to 84.5% in 1962.

In general, the regulatory treatment which has been applied to the affiliates has been somewhat like that of independent producers. On the other hand, affiliates have at times been considered for the type of individual company cost-of-service regulation that is applied to the pipeline producers. They show a relative decline in their share of respondents' marketings but not as much or as consistently as the pipelines and they have had a stable share of the total marketed volumes.

[687]

Q. Does the downward overall trend for pipeline producers as a group mean that all pipeline producers have been remaining static or else decreasing their production activity? A. No, any overall trend usually has its exception I am advised, however, that the only relatively recent entrant into pipeline production engaged solely in selling its produced gas to other pipelines. The other major pipelines which have been called to my attention as possibly representing exceptions to the decreasing trend are the pipelines which have purchased partially developed leaseholds. Since acquiring developed leaseholds does not entail the uncertainties of exploration this type of acquisition does not

conflict with the conclusion that differences in regulatory treatment of pipeline and independent producers has caused a relative decline in the first group.

If the trends which have developed were applicable only to isolated pipeline producers, it might be attributed to managerial discretion, special financial circumstances, or changes in opportunity for a given geographic area. However, when there is such a general decline in the efforts of one segment in comparison to the other segments of the producing industry, this should be attributable to

[688]

a factor affecting all members of that segment. Differences in regulatory treatment would be a factor affecting all members of that segment and could provide the explanation for the decline.

Q. Do you know of any other general factors that could explain the relative decline? A. No. As I indicated earlier, the pipeline producers and the independent producers are comparable in the success of their exploration activities and have similar costs. Thus, other possible explanations–namely lower success ratios or higher costs–are inconsistent with the data cited previously.

Q. Are the differences in regulatory treatment that would account for the relative decline inherent in the method itself or in its administration? A. Any method of regulation could be so administered as to produce a desired profit trend, and profit rates influence business behavior. Logically, a very generously administered individual company cost-of-service method could result in more exploration than group pricing that results in a low level of profits. But even if this were possible in the natural gas producing business, group pricing would still have the following advantage over

[689]

individual cost of service. Group pricing holds out the possibility of above average returns to the more efficient firm;

[689]

thus, it encourages the more efficient group to expand. By such a self-selection more additions to reserves for a given profit level is likely to result from group pricing than from individual company cost-of-service regulation.

Q. Are there reasons why the relative decline in pipeline production should be considered economically costly in view of the absence of any indication pipelines have been unable to meet their current requirements through purchased gas? A. Yes, there are several. First, a number of recent presentations in Commission proceedings raise questions as to whether current exploratory and development efforts are adequate to meet long-term requirements. Exhibit 29 (WPA-8) sponsored by Mr. Anderson, sets forth the American Gas Association's estimate of national gas supply in relation to requirements, showing the downtrend in the ratio. While I am not in a position to evaluate the accuracy of these figures, if there is any substance to the contentions being made by independent producers and others that the requirements will soon outstrip available gas supplies, it would be unwise to have differences in regulatory methods that cause a relative decline in one class of producers.

[690]

Q. What are the other economic reasons indicating the undesirability of further reducing the role of the pipeline producer? A. From the standpoint of an economist, since this is not a franchise activity, all other things being equal, it is economically desirable to have more rather than fewer producers. Of course, other things are never equal and it must be recognized that there are already a large number of firms competing in this market. Even so, there is a presumption against consciously attempting to discourage existing producers from continuing their activities. Moreover, I am aware that in prior proceedings, contentions have been made that the present concentration level in the gas producing industry is too high. Thus, there are those who do not admit that the present conditions provide adequate

safeguards against this concentration. The relative market shares of production by pipeline producers affiliated producers and independent producers is reflected by Exhibit 34 (WPA-13), sponsored by Mr. Anderson. As that exhibit shows, the largest pipeline and affiliate producers, which are underlined, do not rank among the four firms with the largest share of production, the share of the top four being one common measure of concentration. Indeed they do not even rank among the top eight producers.

[691]

Hence, if the market share of the pipeline producers and affiliates continues to decline and some part of their relative decline is matched by a relative expansion of the large independent producers, concentration would increase. While the change might be small, such a result would increase concentration in an activity where questions have been raised about the existing level of concentration.

Q. Are there still other reasons to avoid discouraging pipeline production activities by regulatory actions? A. The major pipeline producers and the affiliated producers, have capabilities for acquisition of leases and for exploration, development and production, as Mr. Dickinson's testimony indicates. If the relative decline should continue to a point that there is a dispersal of capabilities, this dispersal would represent an immediate economic loss. Once this capability is lost it may not be easily recreated if economic conditions require a major acceleration in exploration and production.

Q. Let me now turn to the second general question you mentioned at the outset: what would be the effects of individual company cost-of-service regulation. Please outline briefly the features of individual company cost-of-service regulation?

[692]

A. Under this method, a unit price is not established or assigned to the gas which pipeline companies produce and

transport to their resale markets. Rather the exploration, development, and production expenses of each company for the base or test period are included in the overall cost-of-service of each company and the assets devoted to production are included in the rate base. The Commission has decided not to use this individual company cost-of-service method as a general rule for independent producers, and it is my understanding that the Commission is seeking in this proceeding to determine whether individual company cost-of-service regulation will be continued with respect to the production activities of the pipeline companies.

The individual company cost-of-service regulation is now applied to transmission activities of the pipeline companies. However, there are significant differences between transmission and production activities. First, production activities involve a larger element of managerial discretion than transmission activities. Second, periodic or year to year changes in costs are more unpredictable in exploration, development and production of natural gas.

Q. Would you explain the distinction with respect to managerial choice?

[693]

A. With regard to production activities, the pipelines have a choice as to whether, and to what extent, they should meet their market requirements from entering into, maintaining, expanding, or contracting their own production. Other sources of supply are available to them. The choices of this sort have to be remade continuously. With regard to the transmission activities, however, there are no comparable choices. By definition, if the pipeline company is to meet its market requirements it will have to do so by transporting the gas—which may be either produced or purchased—to the facilities of its customers. Once it has entered into a market area, been certified, and laid the pipeline, a good deal of the managerial choice has been removed from the situation.

Q. How does the factor of managerial choice affect the desirability of a method of rate-making? A. When there is such an element of managerial choice between company production and purchased gas, the rates to consumers should not be directly affected by the choices that are made by company managements. Rather the regulatory approach should be to insulate the consumer from the consequences of such choices and to encourage the best possible choices. This can be accomplished through a regulatory approach in which the pipelines receives the

[694]

same price allowance for a gas supply, however procured, through parity of treatment, and assuming, of course, that individual company cost-of-service pricing is not adopted.

Q. Will you please explain more fully? A. Assuming that there is parity of treatment for gas supply obtained through company production or from affiliated production or from independent producers, and that individual company cost-of-service is not used to determine the allowance or price, all additional gas supplies from a given area would have the equivalent cost impact upon the rate which the pipeline charges its utility customers. If the pipeline is a high cost producer, the company itself will bear the additional cost. The individual cost-of-service method, on the other hand, tends to shift the cost differences forward to the consumer.

Q. Is there any available data from which the individual company cost-of-service differences in cost impact could be approximated? A. Such data, demonstrating the disparity among the individual company unit costs of pipeline producers, affiliated producers and independent producers is contained in the exhibits sponsored by Mr. Jones. His data are for a

[695]

total of 86 producers. If these data are ordered to list companies in the order of their unit costs from highest to lowest and then divided into four quartiles, the three classes of producers are represented in each quartile as follows:

	All Companies	Independent Producers	Affiliates	Pipeline Producers
First Quartile	21	8	6	7
Second Quartile	22	15	5	2
Third Quartile	23	20	2	1
Fourth Quartile	20	11	4	5

While the pipeline producers do not match exactly the distribution of the independent producers, the data demonstrate that all three classes of producers are characterized by a substantial disparity among the individual company unit costs for the production of natural gas.

Q. Why is it desirable for these cost differences to be absorbed by the producers rather than the consumer? A. The producer can affect these costs by his own choices between purchased gas and his own production.

[696]

To insure these choices are made efficiently the spur of losses for poor choices and the carrot of above median rewards for good management is needed. Otherwise, for example, the consumers might have to pay the higher costs where the pipeline undertakes production activity as a matter of preference rather than to minimize costs. Cost-of-service regulation is also inconsistent with encouraging efficient exploration. The higher costs of an inefficient operation would tend to be shifted forward to the consumer and absent a penalty for inefficiency the general level of efficiency would be lower than under some system where the producers would be penalized for bad choices and inefficiency. Even though under a system where the more efficient firms could keep the savings from their efficiency

would limit the immediate gains of the consumers, in the long run the cost savings would likely to be reflected at the consumer level as improvements in efficiency serve to lower, or counteract increases in, the average cost of producers as a group.

Q. You also mentioned year to year changes in production costs as a difference between production and transmission activities. How does this affect individual company cost-of-service regulation?

[697]

A. The concept, as its name implies, is cost recovery of all prudent expenditures involved in the regulated activity. However, in practice costs are unpredictable and regulation never instantaneous so that there may be variance between the costs assumed for ratemaking and the actual costs. However, in natural gas production, exploration costs are more unpredictable than most costs so that this characteristic of individual company cost-of-service ratemaking can be a major problem rather than a normal imperfection.

Q. Upon what do you base that statement? A. An examination has been made of the exploration and development costs for the pipeline producers, from 1955 through 1962, showing the wide year-to-year fluctuations reflected in Exhibit 28 (WPA-7), which will be discussed later. Moreover, from the All-Area Questionnaire we know that the cost of unsuccessful exploration, shown as dry-hole expense and abandoned leaseholds for a pipeline producer, is more than one-quarter of the total expense of producing gas, and this item is treated as a current expense. The exploration costs associated with producing wells are capitalized and added to the rate base. But one cannot have exploration without some failures or dry holes and their associated costs, and hence I am focusing on an important part of

[698]

production costs. For such costs, the problems are threefold. First, some pipelines may not be engaged in exploration. For example, in 1964 a dozen pipelines had no exploration activities. These pipelines, if 1964 were their base year for ratemaking, would have no allowance for unsuccessful exploration or dry-hole expense and would not receive any such allowance until after the costs were incurred. Since rates are not increased to recover past costs, these amounts would not be recovered. Second, if following a rate proceeding in which such a cost was recognized, the pipeline producer continues exploratory activity, his recoverable costs would be limited to those incurred in the test year, or possibly an average of several past years. Thus there is an implied assumption in this method that exploratory activity would be at a constant level, regardless of the needs or opportunities. Third, individual pipeline producers are unable to realize any predicted success ratio, even though an allowance for dry-hole expense assumes a predictable division between dry holes and producing wells.

Q. How has this last point been ascertained? A. Exploratory performance is most directly shown in success ratios since the success ratio determines the

[699]

expenses of unsuccessful exploration which is a substantial component of the cost of service. I have previously discussed the comparability of success ratios among the three segments of the producing industry. However, even though the percentage of successful exploratory wells does not vary markedly among these groups, there is a very wide disparity among the individual companies in each classification, and an even wider variation for each individual company from year to year. This variation is demonstrated by Exhibit 25 (WPA-4), sponsored by Mr. Anderson, which relates to pipeline producers and is based on data from the All-Area Questionnaire. The same type of variation is present in the case

of affiliated producers and independent producers, and is shown on the same exhibit. There appears to be somewhat greater stability in the year to year success ratios of the few very largest independent producers, but there is not evidence of such stability in the case of the largest pipeline producers and affiliated producers.

Q. What is the range of variation for the largest pipeline producers? A. The pipeline producer which reported drilling the largest number of exploratory wells during the eight-year period experienced success ratios varying from 9.8% to 89%.

[700]

The pipeline producer which drilled the next largest number of exploratory wells during this eight-year period experienced success ratios varying from 10% to 85.7%. These ranges of variations apply to most of the firms drilling fewer wells. The producer drilling the fewest wells, apart from those not drilling every year, had a range of variation in its yearly success ratio of 00.0% to 83.3%.

Q. What is the range of variation for the affiliated producers? A. The affiliated producer which drilled the largest number of exploratory wells during the eight-year period experienced success ratios varying from 17% to 36.9%, which is an unusually slight variation. The next affiliated producer varied from 6.4% to 80.1% and the third largest affiliated producer experienced success ratios varying from 18.4% to 67.5%. The affiliated producer drilling the fewest wells, apart from the firms that did not drill in every year, had a range from 00.0% to 68.0%.

Q. Do success ratios reflect the full range of the problem of cost recovery? A. No, they do indicate that a company which has an allowance for dry hole costs measured by a test period in

[701]

which its success ratio was relatively high would be vulnerable to losses in succeeding years in which the exploratory effort was less successful. This is the constant performance assumption, my last point. The method also assumes a constant level of exploration and development drilling. The wide variation in combined number of exploratory and development wells as shown in Exhibit 25 (WPA-4) indicates that this assumption is invalid. The pipeline producer drilling the most wells in total drilled as few as 36 wells in a year and as many as 156 wells in a later year. Similarly, the largest affiliated producer drilled as few as 121 wells in a year and as many as 236 wells in a later year. Substantial variations are also observed in the number of wells drilled by other companies as between years.

With a variation in drilling activity, even a company whose success rates improve in a later year over that experienced in its test year can be precluded from the recovery of its exploratory costs in the year of the improvement in success rates. By drilling a larger number of exploratory wells in that succeeding year, the actual dollars of exploratory expense would exceed the dollars allowed.

[702]

Q. Your illustrations deal with the situations where cost recovery is incomplete. Can it also lead to allowance that exceeds actual costs? A. Yes, there can be that result. If a firm with development activity in the test or base period drills no wells, it would realize additional profits since it would not incur development costs. Similarly, if a firm cuts back its exploratory activity below the level in the test period, there would be an increase in profits. Finally, a high success ratio could reduce dry-well expenses below the level assumed in the base period with a resulting increase in profits.

Q. Could not years of additional profits offset years of unrecovered costs? A. There is no guarantee in the method that there would be perfect offset, particularly for individual companies. The previous cited figures for success ratios show the wide year-to-year variations in individual companies. The above average profits and unrecovered costs would be more in the nature of what the economist calls windfall gains and losses rather than related to better choices and greater efficiency.

[703]

Q. Will you now explain your earlier statement that the cost variations in exploration and development activities exceed those that would be considered the normal imperfections of cost-of-service ratemaking? A. This point demonstrated by Exhibit 28 (WPA-7), sponsored by Mr. Anderson, which compares the fluctuations in annual unit costs for exploration and development with the corresponding figures for transmission, using in the comparison the experience of eleven pipeline producers during the years 1955 through 1962. These eleven companies are the pipeline producers which had active or semi-active exploration and development operations. The remaining three companies, also shown in this exhibit, are substantially inactive in exploration and development. An inspection of the exhibit shows that for each of the eleven companies, the fluctuations in exploration and development costs per Mcf produced substantially exceeded the variation in the transmission cost per Mcf transmitted. The fluctuations in exploration and development costs, together with the other problems I have discussed, create imperfections that exceed those normally associated with individual company cost-of-service ratemaking.

[704]

Q. How would the application of a rate-making method other than the individual company cost-of-service method

[704]

solve the problems of fluctuations in the costs of production operations? A. Certainly it would insulate the consumer from material variation resulting from the pipeline's production operations. Moreover, if parity treatment is utilized the unit supply cost recognized in the rates set for the consumer would be substantially the same whether the pipeline utilized its own reserves or purchased the gas from others in the producing area. Thus the price would be stabilized despite the variations in both exploration success and in supply source. With the application of a method other than individual company cost of service the pipeline producer would still experience fluctuations from these two causes, but such a method would afford the profit opportunity needed to encourage pipeline exploratory effort and production activities and to encourage the best possible management judgment in these activities.

Q. How do you reconcile your criticisms of the individual company cost-of-service method for pipeline production, with the fact that a number of pipeline companies are engaged in production?

[705]

A. As Mr. Dickinson has testified, many of the pipeline producers were substantially engaged in this activity before there was any federal regulation of natural gas pipeline companies, and well before the application of the cost-of-service method. The relevant inquiry is whether the production activities of the pipeline companies have retained their relative importance in comparison with other classes of producers. My examination of the data indicates pipeline production activities have suffered a relative decline.

Q. Do your comments on the undesirability of cost-of-service ratemaking apply to all cases of pipeline production? A. My comments apply to the typical situation in which the pipeline has the opportunity to purchase the gas if it so elects, at a regulated price from other producers in the same general area. The problem may be different in such special situations as when a pipeline cannot purchase the

gas under normal gas purchase agreements, or when a company conducts production activity in its market area to avoid installation of extensive transmission facilities. I have not studied these exceptional situations. My presentation deals with the conditions in which gas supplies could be acquired in the producing areas either by purchase or by development of pipeline-owned reserves.

[706]

PREPARED TESTIMONY OF W. M. ELMER

Q. Please state your name and address. A. W. M. Elmer, 3800 Frederica Street, Owensboro, Kentucky.

Q. What is your present occupation? A. I am president and chief executive officer of Texas Gas Transmission Corporation, a natural gas pipeline company. I am also chairman of the board of Texas Gas Exploration Corporation, a wholly-owned subsidiary of Texas Gas Transmission Corporation. Exploration Corporation explores for, develops, and produces natural gas and crude oil.

Q. Please give your educational and business background. A. I received my college degree in 1936 from the University of Illinois. I am a certified public accountant. From 1936 until 1947, except for a period of service in the United States Navy, I was employed by Arthur Andersen & Co., public accountants and auditors. During this period, I did extensive consulting work for various utilities, and supervised the audit of the accounts of numerous utilities. In June of 1947, I was employed as the comptroller of Memphis Natural Gas Company, a predecessor of Texas Gas. When Texas Gas Transmission Corporation became an operating company in 1948, I became comptroller of that company. Subsequently, I served as treasurer, vice president, senior vice president, executive vice president, and in 1957 I became president of the company.

Q. Will you please state some of the duties which you have performed during your period of employment with Texas Gas?

[707]

A. Prior to becoming president and assuming complete responsibility for the company's operations, I was directly responsible for all financing, sales, accounting, and regulatory matters, and had general supervision of the gas supply activities of the company.

Q. When did your duties regarding Exploration Corporation commence? A. In 1953, I was assigned the responsibility for the formation of Exploration Corporation as a wholly-owned subsidiary of Texas Gas for the purpose of engaging in oil and gas exploration, development, and production operations. I served as president and chief executive officer of Exploration Corporation from 1953 until 1958 when I became chairman of the board.

Q. Have you had any extensive experience with financing matters relating to these corporations? A. I have been responsible for and directly involved in all financing matters in connection with both corporations since 1950.

Q. Will you briefly describe your professional activities relating to natural gas matters? A. I have served for a number of years on the board of directors of the Independent Natural Gas Association of America, and served one term as president of that organization. While president of INGAA, I was a member of the Federal Power Commission's Gas Advisory Council during this period. I have also served as a director of the American Gas Association, and as a director of the Institute of Gas Technology. In addition, I have

[708]

been a member of various industry policy committees and groups.

Q. On whose behalf are you testifying in this proceeding? A. My presentation is being made for the Pipeline Production Group, which is made up of some thirteen natural gas pipeline companies. Their names are a matter of record. They include pipeline companies which have their own production, pipeline companies which have affiliates engaged

in production, and pipeline companies which have little or no production.

Q. What basic position does your group advocate in Phase I of this proceeding? A. The Pipeline Production Group's position is that the Federal Power Commission should:

(1) Afford a parity of rate regulatory treatment for pipeline owned or controlled production with other production:

(2) Price that portion, if any of a natural gas pipeline company's natural gas supply which it produces and delivers to its transmission lines or purchases from a producer subsidiary, owned, controlled, or under common control with it, at the effective area rate or rates per Mcf applicable to gas produced and sold in interstate commerce for resale from such area or areas, but not in excess of the contract price where applicable; and

(3) Further apply the same standards, principles, and criteria in regulating such production, including exceptions

[709]

thereto warranted by particular circumstances, as are applied from time to time in the regulation of jurisdictional sales of gas by other producers.

Our participation in this phase of the proceeding is to bring before the Commission data and fundamental principles which we believe establish both the need and the desirability of parity treatment.

Q. Is it the purpose of the Pipeline Production Group to obtain a special allowance for their own production? A. No. Our basic position, which I previously stated, does not involve any special allowances at all for pipeline or affiliated producers as a class. On the contrary, we believe that it is essential that the Commission adopt a policy for all producers which will assure adequacy of gas supplies at reasonable prices, and that it recognize the necessity for parity treatment in order to achieve this objective through full participation of the entire producing industry. In developing factual data and principles for presentation by the

[709]

group, it has been necessary to use designations such as "pipeline producers" and "affiliated producers" for purposes of identification. However, it is our belief that both the regulatory method and its application should be uniform among all of the companies engaged in exploring for, developing, and producing natural gas for the interstate markets.

Q. Is this, in effect, a request for fair field price treatment? A. No. As I understand it, fair field price contemplates the establishment of a price for natural gas based upon the prices being paid

[710]

to producers in a specified area in an open market where the price is not regulated. We are asking that the pipelines be given the same rate for their own production as established for the independent producers, from time to time, in particular areas. We believe that the comparable characteristics of all producers generally justify and require utilization of data for the various classes of producers in reaching an end result which would then be applicable to each.

Q. To what characteristics of the producing industry do you have reference? A. I would include all significant characteristics, such as technology, methodology, cost incurrence, availability of funds, and capabilities. Some of these subjects will be covered by other witnesses for the group.

One point that graphically illustrates the similarity of characteristics between the independently owned and pipeline controlled functions relates to joint operations. There are innumerable production operations carried on jointly by these two segments of the producing industry. These include joint acquisitions of leases, joint geophysical and geological studies, and joint exploratory, development, and production operations. A trend of this type of arrangement is increasing, particularly with the higher cost prospects in deeper horizons and in the offshore Tidelands areas. The work done by each of the participants is of exactly the

same character and the risks taken are of exactly the same magnitude.

Q. Are there any particular areas of differences in characteristics between the pipeline and independent producers which require consideration?

[711]

A. There are some differences, but not in the basic characteristics of exploration, development, or production. The primary difference relates to the lesser degree of exploratory drilling conducted by pipelines which, in my opinion, is attributable to the difference in rate treatment resulting from regulatory policies. I believe this difference would disappear and that exploratory drilling by pipelines would substantially increase if uniform treatment is applied to all segments of the producing industry.

There presently exists, and has existed in varying degrees for several years, in the minds of pipeline executives, the question as to whether or not pipeline owned or controlled production will be given the same treatment by the Federal Power Commission for rate purposes as that of the independent producers.

I am convinced that there has been less exploratory drilling and production activities by pipeline owned and controlled producing organizations than would have existed had we been assured that the regulatory treatment which the industry would receive, rate-wise, would be the same as that which the independent producer will receive. A few pipeline companies have withdrawn from or have made no effort to go into the producing business although they have expressed interest in doing so. One of the principal reasons that there has been even as much exploratory drilling and production activities by pipelines and affiliates is that some of us, including our own company, have been living in the hope that the Commission would adopt a policy which assures us of equal treatment with the independent producers. As to the future, I am also certain that, should the Commission either

[712]

continue to leave this matter unresolved or decide that the pipeline companies will not be given equal treatment, there will be a material reduction in the production operations of pipeline companies and their affiliates or subsidiaries. This would be very unfortunate in view of the many reasons why, in my opinion, it is in the public interest for pipeline companies to be in the producing business either through a division or an affiliate, as I will explain later in my testimony. Beyond this, the consequences of such a decision would be reduced quantities of gas reserves available to the industry since we are talking about a significant number of pipeline and affiliated producers which would be affected.

Q. Why would the pipelines materially reduce their production activities if they are unable to obtain parity treatment at this time? A. The funds initially invested in building up a production operation come from the company's stockholders. It is management's responsibility to see that these funds are invested in such a way that the stockholder is adequately protected. The business of searching for and producing gas and oil is undeniably a very difficult, competitive, and risky one. A pipeline company either going into the business, or attempting to stay in the business, must compete against years of experience of personnel of much larger companies among the independent producers. Management cannot justify investing these funds in the same business when they know, before they start, that they will not be playing under the same rules, as far as the price of their product is concerned, as are their competitors. It will be difficult enough to compete under the same rules but, without a parity of rate treatment, I

[713]

do not see how any pipeline management can be expected to continue investing in production operations.

Q. What other problems do you visualize from the point of view of management incentives if the Commission should adhere to the individual cost-of-service approach? A. One of the problems to my mind is the fear that such an approach might lead to a "heads I win, tails you lose" philosophy. If a company does well under this approach it receives only its costs, including a return. However, if its costs are substantially above the area rates, there is the chance that an intervenor, or representative of the Commission's Staff, may raise a question as to the prudency of the costs of the program and contend that some portion of the costs should be disallowed. This is a risk which I would find hard to accept since I doubt that this Commission would be prepared to say, in announcing its adherence to a cost-of-service approach, that it will allow any level of costs, irrespective of the magnitude, which a pipeline company may incur in its production activities.

Q. Is it your opinion that the individual company cost of service treatment could appropriately be made compatible with production activities of pipelines and their affiliates? A. I do not believe so. Many of the cases in which the Commission has considered the questions of rates to be established for

[714]

pipeline companies with on-system production have swelt on the concept of the proper rate of return to be applied to the pipeline company's investment in production property. Substantially all of the tests which the Commissioners have suggested relate to the question whether a greater rate of return should be applied to those properties than that which is applied to the pipeline company's transmission plant. With all due respect, I do not believe that an increased rate of return applied to an individual company rate base is any solution to this problem, whether the producer is a pipeline producer or an independent producer.

Q. Will you please explain the basis for your statement concerning the inappropriateness of individual company rate

[714]

of return as a basis for assuring production activities? A. An individual company rate of return approach necessarily requires individual company cost of service, and a cost of service approach is no more appropriate for pipeline production than for production by an independent producer. Had the Commission not already made the determination that the individual company cost of service approach is not appropriate

[715]

for independent producers, we would not be in this type of proceeding today. The cost of service rate approach was adopted and has been developed for a utility type of industry in which the return from capital invested by each company in its utility plant can be estimated with reasonable accuracy, and in which revenues and expenses vary generally in proportion to plant investment. This pattern definitely does not fit the producing business. The production of gas and oil by a pipeline is the same risk business as it is for the independent producer. It is one in which a company may have a predominance of unsuccessful exploratory wells in one year, and then a predominance of successful exploratory and development wells in another. Investments in leases may be held for years, developed over a long period of time, or else dropped. The over-all earnings objective of a successful production operation is to carry on the leasing, geophysical, geological, and other programs which may take months or years, looking forward to the hopes of finding production that will generate revenues adequate enough to provide earnings which, over a period of time, will produce enough good earnings years to offset the bad ones. As I have stated, this problem is exactly the same for the independent producer as it is for the pipeline affiliate or producing department.

Q. Do you believe that there is any danger to the financial integrity of the pipeline companies through participation in the high-risk production operations? A. No, I do not.

It is true that the production business has considerably more risks than that of the pipeline operations. On the other hand, with proper management, this business can be successful as has been

[716]

demonstrated by the many successful independent producing companies operating throughout the United States. One of my responsibilities, as president of Texas Gas, is to maintain communications with many funds, pension trusts, security analysts, and other investment groups. In my opinion, the majority of these poeple believe that a well-managed production department or subsidiary is an asset to the financial standing of the pipeline company.

Q. Are there any basic differences in financing exploratory and related production activities of a pipeline or a pipeline affiliate and an independent producer? A. Basically, there are none. The initial financing of the affiliate or production division is based on retrained equity of the pipeline company, just as the initial financing of an independent producing company would come from funds advanced by its owners. Once the operation is underway, and through its development stages, the pipeline production department or producing subsidiary can finance its operations substantially the same as the independent producer. It generates its cash from the sale of its product; it can also borrow money through oil payments or other pledging of producing properties. If an extraordinary amount of cash is required, such cash can be advanced to the subsidiary or production division by the pipeline in the same manner as the independent producer would obtain additional funds in the form of the sale of equity securities or borrowings. Some independent producers, which are subsidiaries of non-regulated companies, borrow their funds for these extraordinary needs from the parent company in the same

[717]

manner that the pipeline division or subsidiary would from its pipeline parent. As a general rule, neither the pipeline affiliate nor the independent producer has any material amount of long-term debt based on its producing properties.

Q. Apart from the similarities and comparability among the various categories of producers, are there any other reasons for modifying the regulatory policy so as to encourage further production activities by pipeline and affiliated producers? A. Yes, I believe there are. I am convinced that there are definite advantages for a pipeline company to be engaged in an exploration and production operation in meeting its obligations, both to the consuming public and to its stockholders. I believe that a pipeline company which has carried on an aggressive exploration and development program will be better able to supply gas to its customers, particularly during a period of short gas supply. Some of the basic advantages are:

(a) Production by a pipeline company or purchases from a producing affiliate gives the pipelines a more flexible gas supply. Control of production affords flexibility in scheduling purchases and allows greater swings in periods of maximum and minimum demand.

(b) When unused capacity develops in portions of the gathering and transmission systems, the pipeline producer or affiliated producer can intensify its efforts to develop production from geographic areas which will relieve the unused

[718]

capacity problem. Similarly, significant discoveries by a pipeline or an affiliate in such an area will generally result in stepped-up exploratory work by other producers.

(c) A management team in a transmission operation which has been charged with the responsibility of a production operation gains experience in the production field, which experience is of great value in dealing with producer sellers.

(d) A well-managed producing department or subsidiary of a pipeline company which can supplement the earnings of the pipeline company itself is, as I have stated previously, looked upon very favorably by security analysts and investors generally. Such an operation, if successful, from an earnings standpoint, makes it easier for the pipeline to compete with other industry for capital in the money market.

Q. You included a statement in your previous answer that related your answer to a period of short supply. Did you intend to limit your answer to this period? A. I did not so intend. While these reasons may be more applicable in periods of short supply, they are very important at all times. Furthermore, the companies which have not maintained a continuing exploration and production operation cannot commence such activities and find gas overnight, and thus wait until a period of short supply. The history of the producing business shows that most major discoveries have resulted from years of work involving geological interpretation of general areas, acquisition of

[719]

blocks of leases, extensive geophysical work, and actually drilling wells to test the interpretation of these data. Even prior to this, a great deal of time is required to build a capable and experienced organization. Therefore, if the management of a pipeline company desires to be in a position to develop gas reserves, including portions of those required by it for expansion or replacement of depleting supplies, it must continually maintain and possibly expand its exploration and production operations.

Q. Mr. Elmer, would the encouragement of pipeline production which, in your opinion, would result from the adoption of parity of rate treatment, adversely affect the independent producers? A. No, it would not. There has developed over the past few years a continuing reduction in the amount of uncommitted gas available to the interstate pipeline companies, primarily in South Louisiana and

[7191

Texas. Five years ago, this was not the case. The gas available at that time has, for the most part, been dedicated to both intrastate and interstate markets. There are no substantial gas reserves available today in that area for acquisition. We all know that the demand for gas for both the interstate and intrastate markets will increase. Personally, I believe that there are great quantities of gas still awaiting discovery if producers are given the economic incentive to do so. But, the key factor is this—there is only one way to discover gas and that is to drill exploratory wells. We need everyone possible, including the pipelines and affiliates, drilling those wells. The amount of gas which will be discovered by both the independent producers and the pipelines will certainly find a ready market; and, therefore, in face

[720]

of the demands which exist now and will exist in the future, the encouragement of increased production activity by the pipelines will not in any way harm the independent producers. Aside from the effect on the independent producer, everything that can be done to encourage greater efforts on the part of the pipeline and the producer to find the gas supplies needed for the future most certainly is and will continue to be in the public interest.

Q. Would the cost of gas to the consumer be increased if pipeline producers are accorded the same treatment as individual producers? A. No, in my opinion the contrary would be true. In the first place, over the long pull the price of gas in the field will reflect quantities available in relation to the demand. We all know that there is a substantial intrastate market. Under conditions of shortage, most available gas would be channeled into unregulated markets. This situation cannot be avoided except through assurance of adequate supplies for both markets. The greater the participation of the pipeline industry in exploration and development, the more supplies we can look forward to and the less will be the pressure of increasing demands on the price. To my mind this consideration far

outweighs the question whether the output of a particular pipeline producer from a particular field will cost a few cents more or a few cents less under one system or the other. This proceeding will have an important bearing on the future of the pipeline industry, and it should be decided on broad grounds.

Even with respect to the pipeline producer which would continue its production operations whether under the existing rules or under

[721]

the parity proposal we advocate, I believe the area rate system would be far preferable for the pipeline's customers. The Commission has rightly justified the area rate approach on the ground, among others, that it eliminates the cost-plus regulation technique in an economic area where this technique is exceedingly difficult to apply. There are few norms to aid the Commission in determining whether an exploration program has been conducted at minimum cost. In this respect production is entirely different from the typical utility operation. It seems to me inevitable that there would be greater pressure on management to do the most economic job possible if it knew that within the limits of the area ceiling, profits or losses were for its own account. I remind you that the pipeline producers as a group could not earn extraordinary profits on area rates because area rates are cost-related, but they are cost related on an area or average basis and not on the basis of particular wells or fields and this makes a great deal of difference insofar as management incentive is concerned. If individual cost-plus arrangements are not sound for the independent producers, they are equally unsound for pipeline producers.

Q. You have said that the financial community regards a well-managed production operation as an asset to the financial standing of a pipeline company. Is this not incentive enough for the pipeline to enter or continue in production? A. I do not think so, because the industry sees on the horizon the risks and problems I have described. It may

[721]

well be that some pipelines will remain in production irrespective of the

[721-A]

outcome of this proceeding, but I am sure that in general the industry's interest in production will be small compared to what is to be expected if we can function under the area-price system. Moreover, even the companies which continue in production will not be able to serve the public interest to the same degree as if they can participate on the same terms as the majors. On these terms they would have additional incentives to do a more economical job, and to relate their production activities to the best possible performance of their pipeline responsibilities.

* * *

[731]

PREPARED TESTIMONY OF H. E. ROWE, JR. ON BEHALF OF TENNESSEE GAS PIPELINE COMPANY, A DIVISION OF TENNECO INC.

* * *

[734]

Q. Do you have an opinion or any facts available bearing on such issues? A. Yes, I have an opinion on a number of the issues posed in the Examiner's Order.

At the outset, I think that there can be no doubt that anyone having the capital, the know-how and the desire should be encouraged to explore for natural gas. This obviously includes pipeline or affiliated producers who have a great stake in the availability of adequate future supplies of gas.

The need for encouraging exploration for natural gas reserves becomes evident, in my opinion, when one takes into account the enormous

[735]

task ahead of finding gas reserves adequate to meet the future natural gas requirements as estimated by responsible sources.

In this connection, the Commission, in the *Alabama-Tennessee* case, Opinion No. 417, referred to various forecasts of gas consumption, noting that all of the forecasts estimated a growth in gas consumption in the future. A very recent estimate of future natural gas requirements was published in June, 1967 by the Future Requirements Committee under the auspices of the Gas Industry Committee, which is a joint committee of the American Gas Association, the American Petroleum Institute and the Independent Natural Gas Association of America. According to this recent report, which is prepared in cooperation with the Denver Research Institute of the University of Denver, the Committee's estimates of natural gas requirements of the United States are:

Year	Annual Requirements (Trillion Cubic Feet at 14.73 psia and 60°F)
1966	17.8
1967	18.8
1968	19.7
1969	20.7
1970	21.5
1975	25.5
1980	28.6
1985	32.0
1990	36.0

When broken down by regions, the report indicates that the requirements of the New England Region, which is served in part by Tennessee, will grow to 505 billion cubic feet by 1990, as contrasted with requirements of 132 billion cubic feet in 1961. The requirements of the Appalachian Region, which is also served in part by Tennessee, are esti-

[735]

mated to grow to over 6 trillion cubic feet in 1990, as contrasted with requirements of 2.4 trillion cubic feet in 1961. The requirements of the Southeast Region, which is

[736]

served in part by Tennessee, are estimated to be 2.5 trillion cubic feet in 1990, as contrasted with requirements of 821 billion cubic feet in 1961. The requirements of the Great Lakes Region, which is served in part by Tennessee through its sales to Midwestern Gas Transmission Company, are estimated to be 4.4 trillion cubic feet in 1990, as contrasted with 1961 requirements of 1.3 trillion cubic feet.

According to the Report, the cumulative natural gas requirements between 1966 and 1975 will be 218 trillion cubic feet and the cumulative requirements between 1966 and 1990 will be 680 trillion cubic feet. This is to be compared with estimated proven recoverable natural gas reserves of 286.5 trillion cubic feet nationally as of the end of 1965 as reported on page 121 of the Commission's 1966 Annual Report to Congress.

* * *

[741]

PREPARED TESTIMONY
OF
J. M. JOHNSON, JR.
ON BEHALF OF
TENNESSEE GAS PIPELINE COMPANY,
A DIVISION OF TENNECO INC.

* * *

[742]

Q. Have you read the Presiding Examiner's Ruling on Issues dated June 16, 1966 in the instant case? A. Yes.

Q. Do you have an opinion or any facts available bearing on such issues? A. Yes, I have an opinion on a number of the issues. The Examiner's order poses the following question:

"What should be the effect of pipeline (and affiliate) production area rates on various aspects of individual pipeline rate determinations, such as but not limited to rate of return and income tax

[743]

allowance? For example, should Federal income tax deductions and liquid extraction revenues related to pipeline (and affiliate) production be reflected in the pipeline's jurisdictional cost of service?"

Insofar as the income tax allowance is concerned, any tax benefits related to pipeline production should not be credited to the pipeline's cost of service if an area rate is adopted. This follows from the fact that pipeline producers and independent producers should be treated the same insofar as price regulation is concerned. Since the area rate is derived on the basis of a composite cost of service for the area which already reflects tax benefits related to gas production, it would be improper to again credit these tax benefits when determining the pipeline cost of service, just as it would be improper for a pipeline to seek to include in the cost of service expenses related to production which it is already being compensated for in area rates. In other words, the area rate received by the pipeline has already been adjusted to reflect the extent of the tax benefits.

By the same token, it would be improper to credit the cost of service with the liquid extraction revenues, since such revenues are taken into account by the Commission in arriving at the area rate. Since it is our position with respect to Phase I of this case, that the Commission should treat pipeline producers and independent producers alike, it follows that liquid extraction revenues should not be credited to the pipeline cost of service because this would, in effect, reduce the compensation for pipeline production below

[744]

that which is allowed to independent producers.

Going to other issues raised by the Examiner's order, I believe it is feasible to treat pipeline production from leases acquired subsequent to the date of the order in Phase I of this proceeding on an area rate basis and to treat pipeline production from leases acquired prior to such date on a cost of service basis in arriving at pipeline rates. This can be accomplished in the cost of service by simply segregating the test year pipeline production adjusted for any known changes, between production which came from pre-Phase I leases and and post-Phase I leases. A cost of service per Mcf could then be determined for the pre-Phase I production using traditional methods, whereas the post-Phase I production would be priced on an area rate basis.

As to the implementation of a Commission policy decision to put on-system pipeline production from future reserves on an area price basis, this could be implemented in a Section 4 pipeline rate filing, or a Section 5(a) pipeline rate investigation by allowing the area rate for pipeline production in lieu of expenses and return on investment related to leases acquired after Phase I in the determination of the pipeline's cost of service. Where an area rate has not been determined for a particular producing area, then it is my view that the Commission should apply either the guideline or in-line price, as the case may be, in determining the pipeline cost of service. In other words, the Commission should, in my opinion.

[745]

allow the same price in the cost of service of the pipeline for the post-Phase I pipeline production that it would allow an independent producer in that area selling gas to a pipeline.

* * *

[747]

PREPARED TESTIMONY OF E. L. DUNN

Q. Will you please state you name and address? A. Edward L. Dunn, 724 9th Street, N. W., Washington, D. C.

Q. Mr. Dunn, what is your present business occupation? A. I am a vice president of H. Zinder & Associates, Inc., whose principal office is at 724 9th Street, N. W., Washington, D. C.

Q. Will you give us a brief description of the firm of H. Zinder & Associates, Inc.? A. H. Zinder and Associates, Inc. is a firm of public utility consultants having offices in Washington, D. C.; Dallas, Texas; Houston, Texas; Seattle, Washington; and New York, New York.

* * *

[748]

I was associated with, supervised or testified in every major rate proceeding before the Commission during the fourteen-year period of my employment with the Commission. Also, as technical advisor, I participated with the Office of the Solicitor General of the United States in the preparation of briefs in rate cases before the United States Supreme Court. Since February 1951, I have been employed in my present position, the duties of which consist principally of studies, reports and testimony of matters involved in natural gas rate cases and natural gas certificate cases and in the direction and supervision of other persons similarly engaged.

The cases which I have supervised or in which I have testified, both when with Federal Power Commission and since, are so numerous that it would be quite space-consuming to specify them by title, docket numbers and citations.

* * *

[764]

Q. Please describe generally the experience of Union Producing Company under regulation. A. Since Union has always operated as I have described and has always sold a substantial volume of the natural gas it produced to its affiliate United, it is typical of the relationship between a production company and an affiliated interstate pipeline company, in the class I am explaining.

Its regulatory history confirms the character of its sales as I have stated. The Commission, by order issued March 9, 1956, instituted an investigation of Union for the purpose of determining all facts concerning Union's operations to enable the Commission to determine whether Union is a "natural gas company" within the meaning of the Natural Gas Act. United was declared a necessary party because of its affiliation with Union, and because it had information deemed pertinent to the investigation. To this end the Commission required, among other things, Union and United to submit full information and maps showing full details of all facilities, deliveries and sales, and all contract information relating to such purchases and sales (copies of Union's gas sales contracts were furnished).

[765]

The Commission found, *Docket G-10060 Union Producing Company and United Gas Pipe Line Company*, 18 FPC 387, that the bulk of Union's gas sales were to pipeline companies which are natural gas companies within the meaning of the Natural Gas Act such as United, Olin Gas Transmission Company, Arkansas-Louisiana Gas Company, Louisiana-Nevada Transit Company, Southern Natural Gas Company, Trunkline Gas Company, Wilcox Trend Gathering System, Inc., and Lone Star Gas Company and that such customers transport and resell such natural gas in interstate commerce for ultimate public consumption.

Union was held to be comparable in every respect to Deep South Oil Co., the Commission citing *Deep South*

Oil Company of Texas, Docket No. G-2952, 14 FPC 83. The Commission held that *Deep South* involved, as does Union, sales of natural gas by an "independent producer" and upon the authority of *Deep South* and the cases cited therein, held that Union is a natural-gas company within the meaning of the Natural Gas Act, further stating:

> "Clearly, from the factual situation disclosed by Union's and United Gas' submittals, Union is manifestly an 'independent producer' of natural gas within the meaning of Part 154 of the Commission's Regulations under the Natural Gas Act." (18 FPC 390)

Union has filed its rates and charges for jurisdictional sales pursuant to Regulations 154.91 through 154.103 applicable to "independent producers," and the Commission has accepted such filings.

Union was named as an independent producer respondent in each of the area rate proceedings covering areas in which Union operates and Union has filed the All Area Questionnaire with the Commission in AR61-2.

Q. Please explain the regulatory significance of affiliation in

[766]

reviewing rates between a producing company of the class you have identified and an interstate pipeline company of the class you have described. A. Prior to the 1954 decision of the U. S. Supreme Court in *Phillips*, it was unquestionably necessary, for regulatory purposes, to closely scrutinize prices of gas between an unregulated producing company selling gas to a regulated natural gas pipeline company. The specific problem that arises from corporate affiliation has its origin in the fact that when a *regulated* company acquires supplies or services from an *unregulated affiliate* lack of regulation and arms-length bargaining provided freedom by which the corporate organization had the opportunity to transfer costs or profits which unduly advantaged the stockholders to the potential disadvantage

[766]

of the customers of the regulated company. Scrutiny gave the answer whether the opportunity had been taken. Regulation furnishes restraint, and that restraint insures against any advantage. Where lack of regulation exists in the transactions with an affiliated seller, the price should be no higher than would be fairly payable in a regulated business by a buyer unrelated to the seller and dealing at arms-length. This furnishes the same restraint as that from regulation.

The criticism which commissions and courts have directed at affiliation turns upon the basic and decisive factor of the lack of regulatory restraint on the unregulated affiliate from whom services and supplies are acquired at unregulated prices by the regulated company. Regulation provides restriction; the presence of regulation prohibits freedom of the corporate organization to transfer excessive profits or advantages from affiliates and assures the integrity of inter-company prices.

[767]

Since June 7, 1954, there has been no regulatory significance due to affiliation in the regulatory review of the reasonableness of rates and charges for gas sold by a producing company to an affiliated interstate pipeline company because the producing company has been subject to rate regulation. This is necessarily true, because such regulation guarantees the integrity, fairness and reasonableness of such transactions among affiliates more strictly than any other method of regulatory supervision or scrutiny.

Q. Will you please state your conclusions with respect to the proper regulatory treatment for the class of producers you have discussed? A. It is my conclusion that it is not only proper, but absolutely essential, that the Commission, in reviewing and determining just and reasonable rates for all "independent producers," including that class of "independent producers" which I have discussed, of which Union is typical, use the same regulatory methods and principles followed to determine justness and reasonableness for all

"independent producers," including that class of "independent producers" which I have discussed, whether it be some "cost" method, an area rate method, or any method which the Commission at any time in the future may select, and this is so whether it apply to gas described as "old" gas or "new" gas or by any other name.

* * *

PREPARED DIRECT TESTIMONY
OF V. M. PLUMMER

* * *

[899]

Q. What are some of the characteristics or requirements which, in maintenance of adequate gas supply for its customers, would require more pronounced production activities on the part of one pipeline company than on the part of another? A. The principal factor is, of course, the absence of long-term natural gas supplies. Other factors would include the geographical location of available supplies in relation to the pipeline system, the quality and type of the gas available, the conditions under which it may be acquired, including price, and the operational considerations of the pipeline requiring additional supplies, such as the availability of storage, system load factors and the necessity of swing sources.

If gas can be purchased by a pipeline company under a conventional gas purchase agreement and in the quantities, under the conditions and at the times when it is required to satisfy new and growing markets, the need for extensive pipeline production activities on the part of a pipeline company would not be prominent. However, if possibility exists that a pipeline's utility function cannot be sustained by means of purchased gas, pipeline production activities are required if the consuming public is to receive the benefits of natural gas service.

[900]

That all pipeline companies have not sensed an absolute need for their own production to insure maintenance of adequate gas supplies for their respective customers is revealed by the degree to which pipeline companies presently own reserves. As disclosed by the Federal Power Commission publication, *Statistics for Interstate Natural Gas Pipeline Companies* for the year 1965, of those 36 pipeline respondents in this proceeding, 24 had production from company-owned reserves. Of those 24 companies having their own production, company-owned reserves constituted only 11.6% of total reserves committed to or controlled by such companies. For El Paso, company-owned reserves constituted some 24% of its total reserves.

Q. Has it been necessary for El Paso Natural Gas Company to engage in pipeline production activities to insure adequate gas supplies for its customers? A. Yes, it has.

[904]

*** We finally concluded arrangements with the principal single owner of uncommitted reserves in the Basin. The only arrangement which was acceptable to this party was for El Paso to purchase the existing wells and the underlying reserves, with the producer retaining an overriding royalty on the production. We had exhausted every possible means of acquiring the gas well gas necessary to enable us to serve our markets except under this type of contract. We were thus forced into the position of purchasing large blocks of acreage under this type of contract and of developing those quantities of gas well gas which would permit us to serve our growing market areas. While our production activities were concentrated in the San Juan area, the Company also undertook similar activities elsewhere.

* * *

[905]

Q. How have El Paso's company-owned reserves been utilized in the years since their acquisition? A. They have served the exact purposes for which they were originally acquired—they have increased our total supply and have enabled us to even the fluctuations in availability from casinghead gas then held by El Paso by contract and from casinghead reserves which subsequently became available. These reserves have thus permitted El Paso to provide adequate service to existing and new markets which, absent them, would not have been possible. In addition, El Paso's production activities have afforded the Company the benefits which, in general, flow from production activities conducted by any pipeline.

Q. What are these benefits? A. Benefits which have been and continue to be of marterial assistance in the operation of our pipeline operations include the following:

El Paso's company-owned reserves have afforded it substantial flexibility of operation in meeting peak market demands. They have, in effect, provided some alternative to controlled storage. El Paso has

[906]

obtained a majority ownership in numerous producing fields and in virtually all instances where its ownership is substantial, El Paso functions as operator. During periods of peak market demand, the withdrawal rate from Company-owned and operated properties can be substantially accelerated. The control thus afforded through our ownership and operation permits us to utilize our company-owned sources on very little notice and under all conditions of adverse weather while, in such circumstances, purchased gas, operated by the independent producer, is not so readily available.

In any given field or area where a pipeline has acquired a substantial working interest, it is in a position to control development through its own drilling activities. While a pipeline company in such situation cannot foreclose other working

[906]

interest owners from drilling, and there is no need to do so, if others do not develop, the developmental activities undertaken by the pipeline company will accelerate development by others.

The presence of company-owned production in substantial quantities provides the pipeline purchaser with a better bargaining position for the acquisition of reserves by contract from the independent producer. This is particularly apparent where the pipeline provides facilities to move gas from a field and thereby establishes a ready market for its production as well as the production of others.

Similarly, a pipeline company's exploratory effort in a given area influences exploratory effort of the independent producer. The pipeline's active participation provides assurance to the independent producer that

[907]

gas developed will be connected if evidence in early stages of exploration proves the location of gas.

The technology developed and the information gained from production activities likewise benefit the pipeline. They provide invaluable experience and knowledge which enable the pipeline to act intelligently in production matters, to purchase gas with a high degree of competency and to otherwise fulfill its responsibility of providing adequate gas reserves for its customers.

Q. How have El Paso's past production activities differed from those conducted by an independent producer? A. The nature of the activities and the purpose for which they were pursued constitute the principal and significant differences.

As I have stated, El Paso's production activities became mandatory in order to assure not only rendition of new service but continuance of existing service as well. Unlike the independent producer, who has both a choice of whether to enter the field and to what purchaser or market to sell the product, El Paso's utility responsibility did not provide it with a practical choice. Our activities were required for and they were directed to the benefit of our customers; the gas developed was made available for their use.

Likewise differing from the independent producer, our activities were oriented to a search for natural gas, rather than liquids in particular or hydrocarbons in general. I would also note that El Paso's production activities were conducted largely in those geographical areas

[908]

where gas developed could readily be made available to our customers.

A further difference is that El Paso was forced to acquire substantial reserves through purchase of partially developed, proven acreage with attendant higher cost, either in the form of bonus or royalty.

Q. Do you visualize that El Paso will engage in production activities in the future? A. El Paso would propose in the future to continue to engage in production activities to the extent required to assure the availability of adequate, long-term gas supplies for its customers. Conduct of these activities to the degree required in the past will not be necessary if the independent producer is successful in developing increased quantities of gas and if such gas can be economically obtained by us under conventional gas purchase contract.

El Paso has accumulated a vast amount of geological and geophysical data and it has an experienced staff. Our continued presence in production areas will keep us abreast of natural gas developments and will stimulate exploration activities of independent producers in areas in which we are interested. It will permit us to continue activity at levels which can be either intensified or reduced consistent with independent producer activity so that advantage can be taken of all gas made available on favorable terms from independent producers. In the event adequate supplies are not forthcoming from the independent producer, this activity will enable us to promptly and intelligently intensify exploration and development activity or to acquire proven reserves from

[909]

an independent producer in those situations where the reserves could not be obtained through conventional gas purchase contract for whatever reasons may prevail.

Q. What type of rate treatment do you recommend for El Paso's future pipeline production activities you have described? A. It should be accorded rate treatment for such activities which will return to it the costs incurred plus a fair return on its investment.

* * *

[911]

PREPARED TESTIMONY OF
E. WAYNE CORRIN

Q. Will you please state your name and address. A. E. Wayne Corrin. 445 West Main Street, Clarksburg, West Virginia.

* * *

[914]

*** First off, we are, first and foremost, a distributor. Our resale market is, of course, important to us, but revenues from our distribution sales constitute approximately 80% of our revenues.

* * *

[920]

Q. Mr. Corrin, why, in your opinion, does the achievement of the objectives which you enumerated call for the adoption of the "area rate" concept for gas produced by pipelines in the Southwest production fields? A. As pointed out by Mr. Schmidt, the Supply Company's Southern Louisiana production operations are similar in nature to the operations conducted by the independent producers in that area. The technology is the same and the risks comparable.

In fact, we are engaged in a number of joint ventures with the independent producers in Southern Louisiana where the drilling and operating costs are shared on a *pro rata* basis. In these circumstances, I think it essential to grant pipelines equal treatment with the independent producers.

Should the pipelines and the independent producers receive dissimilar rate-making treatment, the class of producer receiving the lesser incentive will be unable to compete in the capital market for funds and in the field for leases.

* * *

[927]

PREPARED TESTIMONY OF
J. J. SCHMIDT

Q. Will you please state your name, business address and occupation. A. My name is J. J. Schmidt; my business address is 202 Richards Building, New Orleans, Louisiana 70112. I am an oil and gas consultant.

* * *

[940]

Q. Mr. Schmidt, are Consolidated's Southern Louisiana production operations similar to the operations of other producers in South Louisiana?

[941]

A. Yes, in most respects I would say that they are identical. As I previously pointed out, we are engaged in many joint ventures with other producers. This is a common practice in Southern Louisiana, particularly in the offshore area.

* * *

[944]

PREPARED TESTIMONY OF CHARLES H. FRAZIER

Q. Will you please state your name, address and qualifications? A. My name is Charles H. Frazier and my address is Downingtown, R. D. 2, Pennsylvania. I am an independent public utility consultant, with offices in Philadelphia, and I am associated with National Economic Research Associates, Inc.

My educational background consists of the completion of a course leading to an A. B. degree at Haverford College, 1924, and such studies as were required to receive the degree of Bachelor of Science in Electrical Engineering from the Harvard Engineering School in 1926.

* * *

[946]

More recently, at the request of the Presiding Examiner in AR61-1, I responded to certain interrogatories which he, and subsequently Staff Counsel, put to me on the general subject of rate design for the purposes of that proceeding. Finally, I testified on behalf of Associated Gas Distributers in the Southern Louisiana Area Rate Proceeding (AR61-2) and the Texas Gulf Coast Area Rate Proceeding (AR64-2) on the same subject.

* * *

[947]

Q. Under what auspices and to what purpose are you testifying in this proceeding? A. I have been asked by Consolidated Natural Gas Service Company to frame rate policy recommendations as to future pipeline produced gas which will be consistent with both the factual matters to which other Consolidated witnesses have testified in this proceeding and the general producer rate policies which Consolidated, among others, has advocated in the area rate proceedings.

Q. Would you please then, at the outset, state your general conclusion

[948]

as to this issue? A. The basic issue in this phase of the proceedings is whether the rate standards for gas from leases acquired in the future and dedicated to interstate service by affiliates or departments of interstate pipelines should be based on the individual costs of those particular pipelines or, in the general alternative, based on the area rates which are in the process of development for gas sold by independent producers to these same pipelines. My general response, subject to qualifications which I will discuss at a later point, is that the latter alternative should be adopted by the Commission.

Q. Will you please give your reasons for this conclusion? A. My conclusion is based primarily on the desirability of realizing the various advantages as to which previous Consolidated witnesses have testified, notably in Mr. Corrin's testimony at Tr. pp. , which a pipeline gains by embarking on its own production program.

If these advantages are to be secured, they can best be secured, in my judgment, by permitting the producing division of an interstate pipeline to function under circumstances closely similar to the circumstances under which independent producers find and produce their gas. I do not see how pipeline production can be encouraged unless the Commission creates the circumstances, in respect to rates, which do not in any way disadvantage the pipeline, in its exploration efforts, and enable it to "compete," on even terms, with the independent producers.

[949]

Q. Why do you say this? A. There would seem to be two basic reasons why this is so. In the first place, Messrs. Corrin and Schmidt have testified that the pipeline producer, in the southwestern producing area, operates under the same

[949]

conditions, dealing with the same factors and with very much the same objectives as an independent producer. In all but definition, he is in fact, an "independent producer." Also, as they testify, the pipeline producer often works as a part of a producing group, in connection with the exploration for and development of a given reserve; the majority of its partners being independent producers. Also, it is dealing, in terms of lease acquisition, with royalty owners who are conditioned to dealing with the same producers. To have the pipeline operating under one set of institutional conditions and the independent producers operating on another could only lead to confusion.

Q. You mention two reasons. What is the other? A. The other, and in my judgment the more fundamental reason, has to do with the decision-making process by which corporate executives advance the operations of their different entities. Thus, beginning with the initial approval of capital and operating budgets, and extending through other managerial decisions relating thereto, the proposals of the director of a pipeline's production department must be justified in terms of the objectives to be gained; and these must be quantified.

[950]

In other words, the suggested programs must embody the requisite financial incentive in addition to the less quantifiable advantages Mr. Corrin has discussed. The choice must be made, therefore, if an incentive is to be offered, between an incentive in the form of a fair price (the area price fixed under regulatory auspices) or an incentive in the form of a guaranteed return—say 6-1/2 percent. Let us consider the latter alternative—leaving aside questions of its adequacy, in the production field. From a consumer protection standpoint, it would not be prudent to *guarantee* such a return, no matter how unsuccessful the operation. After all, the pipeline has the reasonable alternative of buying gas at the area price. So we are left with a proposal which might read

"area price or cost, whichever is lower." But this is no incentive at all. The pipeline would be asking the investor for funds with *neither* a guarantee of return or of price—surely a request which would be unsuccessful. Thus the cost alternative turns out not to be protective of the consumer interest, unless materially qualified, but if so qualified, as not providing the necessary incentive to induce the requisite investment.

Q. How do you square an area-pricing doctrine for pipeline produced gas with the decision of the courts in the City of Detroit case (230 Fed. 2nd 810, CADC 1955, cert. denied, 352 U. S. 829)? A. I see a very marked difference between the doctrine which was originally espoused by the applicant in those proceedings and initially adopted by the Commission (later to be remanded by the courts), and the

position here recommended. This (the former) has been characterized as the "fair field price" doctrine. Such a doctrine holds that the standard to be used in determining a pipeline's rates for resale, and specifically the underlying element of costs related to that pipeline's own production, should be the "fair field price" or "reasonable market price," or some like criterion related to the "going price" for gas in the area. This was be solely a *market-related* price.

There is a clear distinction between a price so determined and the area rate structure which the Commission is in the process of developing. Those area rates are based primarily upon cost of service, and will be determined on "just and reasonable" standards. True, the market may have some bearing in shaping the ultimate price structure, but it will not be the key element. Consequently, since area rates established by the Commission should be just and reasonable, by definition, they can thereby meet the consumer protection test posed by the court decisions in City of Detroit.

Q. You speak about consumer protective features. Might not the ultimate consumer be better off if the pipelines were strictly limited to cost, in pricing their own production for

[951]

rate-making purposes? A. The implication in your question is that pipelines' costs would usually be lower than the composite costs of independent producers. I have seen no evidence in the area rate proceedings in which I have testified to indicate that this would be the case.

Q. What about the rate of return component in cost? Would not the pipelines be using 6-1/2 percent money in their production operations, in

[952]

contrast to the higher rate of return allowed independent producers? A. Not necessarily so. The rate of return allowed any given entity, under regulation, is determined by an assessment of the rate required to permit the requisite investments of capital in that entity, so that it may render the required service. This depends, in important measure, on the relative risks involved in the enterprise. The more or less standard 6-1/2 percent allowed pipelines in recent years was derived from an assessment of the risks involved in the gas transportation function. If the Federal Power Commission has correctly assessed the risk in the exploration and production operation to call for a 10-1/2 to 12 percent return, it would be logical for the investment market to require a composite of these two levels, for a mixed concern, depending upon the proportion of the capitalization devoted to each function. It might be noted, parenthetically, that the Commission recognized this situation, and in fixing 10-1/2 - 12 percent rate of return, relied primarily on the data for the non-integrated producers. Thus in proper costing, the *increments* of capital devoted to production should bear *that* rate of return; else how to obtain new capital for those operations?

* * *

[963]

PROPOSED DIRECT TESTIMONY
OF KENNETH L. SMITH

Q. Please state your name and residence. A. Kenneth L. Smith, Bethesda, Maryland.

Q. By whom are you employed? A. Van Scoyoc & Wiskup, Inc., Public Utility Consultants, 1735 K Street, Northwest, Washington, D. C.

Q. How long have you been so employed? A. Since January 15, 1962.

Q. What is your professional and educational background? A. I have B. S. and M.S. degrees obtained in the College of Commerce and Business Administration, University of Illinois. I was graduated with high honors in Accountancy in 1927, and obtained my Master's degree in Accountancy in 1937. My minor field in both undergraduate and graduate study was Economics. I am a Certified Public Accountant in Illinois and Colorado, having passed the Illinois examination in 1930.

Q. Please name professional and honorary societies to which you belong. A. American Institute of Certified Public Accountants, American Accounting Association, Federal Government Accountants Association, Beta Alpha Psi and Beta Gamma Sigma.

Q. What has been your special training and experience in public utility matters and regulation? A. I participated in annual audits of public utility operating companies as early as 1927. In the summer of 1932, as a graduate student, I studied Public Utility Economics at the University of Illinois. On

[964]

December 1, 1936 I was employed by the Federal Power Commission. Since that date, except for periods aggregating about two years, my work has been concerned with public utility accounting, financial and rate matters, mostly in the regulatory field. This has included more than sixteen years

[964]

on the staff of the Federal Power Commission between 1936 and 1945 and between 1953 and 1962. From September 1938 to June 1939, however, I was away from FPC, serving as Assistant Professor of Accountancy and doing research at the University of Illinois.

From 1941 to 1945 I was Assistant Chief Accountant of FPC, and from December 1956 until my resignation 1962, was Assistant Chief of the Bureau of Rates and Gas Certificates and its successor, the Bureau of Natural Gas. My duties while employed by FPC, except for about two years in the Division of Finance (1936-1938), were concerned principally with investigations and cost of service in formal natural gas rate proceedings. Beginning in 1955 this included rate cases of both natural gas pipeline companies and independent producers of natural gas. From 1957 to 1962 I was in charge of, and responsible for training of, the Federal Power Commission's Rate Investigations Staff, which consisted of about 125 employees at its peak. I testified in an electric rate case (South Carolina Generating Company) in 1955, and from December 1956 until my resignation in 1962, served as consultant to the electric rate staff on accounting and income tax matters whenever such services were required.

Between 1954 and 1962 I gave particular attention to the development of staff procedures and standards for computing income tax allowances in rate cases which would be founded on costs actually incurred and avoid inclusion in such allowances of a return or profit not representing cost.

From September 1951 to September 1953 I was an Assistant Controller of the Rural Electrification Administration in charge of the

[965]

Technical Staff. My principal duties consisted of making special studies, supervising research activities, and developing policies and procedures to be applied to the accounting of REA and its borrowers and to audits of borrowers' books and accounts.

From 1945 to 1951 I resided in Denver, Colorado, and devoted most of my time to public utility consulting practice. I participated in several state utility commission cases as a technical aid to, or witness on behalf of, one of the parties to such proceedings. In addition, during that period, I was Professor of Accounting at the University of Denver in 1946 and part of 1947; and at the request of Mayor Quigg Newton, served the City and County of Denver as Manager of Revenue for about five months in 1948, and as its Utilities Officer from June 1950 until September 1951.

Prior to my initial employment with the FPC in 1936 my work included considerable experience in public utility accounting and income tax matters. Immediately after graduation from the University of Illinois in 1927, I was employed by F. W. Lafrentz & Co., Certified Public Accountants, Chicago, Illinois, and remained with that firm seven years. After that for about two years (1934 to 1936) I was top senior accountant in the Chicago office of the large British accounting firm of Deloitte, Plender, Griffiths & Co. (its American offices since merged into Haskins & Sells, CPA's). This nine years of public accounting experience (1927-1936) was highly diversified. About half of it, however, was concerned with annual audits, income tax returns, consolidated financial statements, investigations and special studies for public utility operating and holding company clients.

During periods of my employment by FPC I testified a number of times between 1940 and 1958 in Federal Power Commission proceedings, on behalf of the FPC staff, concerning a variety of accounting and cost of service matters. This included several appearances as a staff policy witness. On two occasions while employed by

[966]

FPC, I testified before Congressional subcommittees.

Since becoming associated with Messrs. Van Scoyoc and Wiskup, I have testified before presiding examiners of the Federal Power Commission in the Matter of Colorado Inter-

[966]

state Gas Company, Docket No. G-16904, concerning cost of service and other cost analysis; In the Matter of United Gas Pipe Line Company, Docket No. RP63-1, concerning cost of service, particularly income tax matters; In the Matter of Wisconsin Michigan Power Company, Docket No. E-7026, concerning cost of service and income tax allowance; In the Matter of Southwestern Public Service Company, Docket No. E-7038, concerning cost of service and income tax allowance; in the Southern Louisiana area rate proceeding, Docket No. AR61-2, concerning composite cost of service and certain related accounting matters; In the Matter of Alabama Power Company, Docket No. E-7183, concerning cost of service.

During 1964 I testified concerning income tax matters in Docket No. U-4660 relating to rates of City Water Company of Chattanooga, before the Tennessee Public Service Commission.

In March 1965, I testified before the Michigan Public Service Commission in the matter of the Investigation of Accounting and Rate Case Treatment of Investment Tax Credit, Case No. U-1171.

In September 1965, I testified in hearings before the Committee on Finance, United States Senate, concerning the treatment, for regulatory purposes, of tax benefits obtained by filing consolidated returns.

In June 1967, I testified before the Iowa State Commerce Commission, on behalf of the staff of that Commission, concerning cost of service in the matter of Davenport Water Company's application for revision of rates under Docket No. U-138.

[967]

Q. Have you written any material relating to accounting or utility ratemaking which has been published? A. Yes.

Q. Would you indicate what it consists of? A. An article which I wrote on the subject of "Capital Gains and Losses in Accounting" was published in the June 1939 issue of "The Accounting Review." The September 1966 issue of

"Management Accounting," published by the National Association of Accountants, contains an article on "A Regulatory View of the Tax Allocation Controversy" which I wrote. While an Assistant Bureau Chief at Federal Power Commission I wrote considerable material on ratemaking principles and procedures for staff information and training. A substantial part of this material was compiled as lectures on various topics pertaining to ratemaking and printed for staff use.

Q. Have you been requested to present testimony on behalf of the Municipal Gas Group in this proceeding? A. Yes.

Q. I hand you a copy of an exhibit (No. 21) consisting of 10 schedules and one appendix, which exhibit bears the title "Compisite Historical Investment, Reserve and Other Data." Was this exhibit prepared by you or under your supervision? A. Yes.

Q. To the best of your knowledge and belief, do the schedules included in your exhibit represent true and correct summarizations of data reported by companies who are respondents in this proceeding? A. Yes.

Q. What pressure base is used in stating gas volumes shown in the exhibit? A. 14.73 psia. It was requested that respondents state gas volumes on this basis in their responses to the Municipal Gas Group data request. When another basis of reporting was indicated in a response the volumes were converted to the 14.73 base before being

[968]

entered on work sheets supporting the volume data used in this exhibit.

Q. Do the composite data shown in the schedules of the exhibit all relate to the Continental United States? A. Yes.

Q. The schedules in your exhibit contain references to Group 1 and Group 3 respondents. What is meant by the term "Group 1" and "Group 3"? A. The lists of respondents so classified in a memorandum of Staff Counsel to respondents dated April 28, 1967, except that I have

included Northern Natural Gas Company in Group 1 in addition to those listed. Appendix A shows the lists of Group 1 and Group 3 respondents.

Q. Why did you reclassify Northern Natural Gas Company as Group 1? A. For the period 1940 to 1952, it owned production properties and engaged in exploration and development activities. In 1952 it transferred such properties to an affiliate, Northern Natural Gas Producing Company. Although the affiliation was subsequently terminated Northern Natural Gas Company had pipeline or affiliated production during substantially all of the period covered in this exhibit.

Q. Please explain Schedule 1. A. This schedule shows the aggregate gross investment in production, exploration and development properties, at the end of each of the years 1940 to 1961, inclusive, as reported to the Municipal Gas Group by Group 1 Respondents, together with related company owned gas reserves (through 1957), as reported to the Municipal Gas Group or as published in FPC Statistics of Natural Gas Companies. The reserve data obtained from the latter source related to three respondents, principally for certain years in the earlier part of the 1940's.

[969]

Columns (3) and (4) show the gross investment (stated in thousands of dollars) and pipeline owned gas reserves in Mmcf, respectively, as reported by the companies which reported both investment and gas reserves. As already pointed out, reserve data published in FPC Statistics were used to a minor extent. The number of companies for which data are shown in columns (3) and (4) is stated in Column (2).

Column (6) shows the composite amount of gross investment (in thousands of dollars) in production, exploration and development properties reported in response to the Municipal Gas Group data request by companies which did not report the related gas reserves, and for which such reserve data could not be obtained from FPC Statistics. The

number of companies to which the investment data shown in Column (6) are related is stated in Column (5).

Column (8) shows in Mmcf the volume of pipeline owned gas reserves reported to the Municipal Gas Group by companies which did not report their investment for a given year. The number of such companies for each year is stated in Column (7).

Column (9) shows the total number of Group 1 Companies reporting the investment and reserve data utilized in preparing this schedule.

Column (10) shows the total gross investment (stated in thousands of dollars) in production, exploration and development properties, as reported in responses to the Municipal Gas Group data request, and is equivalent to the total of Columns (3) and (6).

Column (11) represents the total volume in Mmcf of gas reserves reported as owned directly by Group 1 pipeline respondent companies, as obtained from the sources already explained. It does not include reserves owned by affiliates of pipelines or other suppliers. The volume shown in Column (11) for any given year is equivalent to the sum of the volumes shown in Columns (4) and (8), respectively,for that year. It is evident from the schedule

[970]

that, due to gaps in reporting, the relationship of investment and reserve data shown for the years 1940-1944, inclusive, in Columns (10) and (11), may not be conclusive.

Q. What are the reasons for showing gross investment data in Columns (3) and (10), respectively, for each of the years 1940 to1961, inclusive, while the data shown in the other columns relate to the years 1940 to 1957, inclusive? A. The data obtained from respondents by the Municipal Gas Group relating to production investment covered the years 1940 to 1961, inclusive. Comparable data relating to exploration and development investment covered only the years 1940 to 1954, inclusive, while the gas reserve data obtained by the Municipal Gas Group covered the years

1940 to 1957, inclusive. Schedule 1 is presented as a composite of data obtained by the Municipal Gas Group and is not intended to duplicate any data composited by the Staff. It is anticipated that staff composite data will show production investment for 1962, exploration and development investment for the years 1955 to 1962, inclusive, and reserve data for the years 1958 to 1965, inclusive.

Q. According to the data shown on Schedule 1, was there an increase between the years 1940 and 1961 in the number of pipeline company respondents which directly owned production properties? A. Yes. The number increased from 17 to 21.

Q. Based on the data shown on Schedule 1, what was the increase between the years 1940 and 1961 in gross investment of pipeline company respondents in directly owned gas reserves and facilities for gas production and exploration? A. The gross investment in such facilities increased during that 21-year period from roughly one hundred million dollars to approximately one billion dollars, based on responses to the Municipal Gas Group data request.

Q. What does Schedule 1 disclose with respect to the increase subsequent to 1940 in gas reserves directly owned by pipeline company respondents?

[971]

A. The data obtained in response to the Municipal Gas Group data request concerning gas reserves related to the years 1940 to 1957, inclusive. Gas reserve data for the years 1940 to 1943, inclusive, were only partially reported. It appears, however, that reserve data beginning with the year 1944 can be accepted as reasonably complete. According to Schedule 1 the gas reserves owned directly by pipeline respondents increased between 1944 and 1957 from approximately 15 trillion cubic feet to approximately 21 trillion cubic feet. In this connection it can be mentioned that in the order of five trillion cubic feet of gas reserves owned by pipeline respondents were sold or transferred to other entities during the period 1944 to 1957, inclusive.

This is shown by Schedule 3 which will be explained later in my testimony. The greater part of such reserves were sold or transferred to entities other than those included among the Group 1 Respondents in this proceeding. Sizable transfers were made to non-respondents.

Q. Please explain what is shown in Schedule 2. A. This schedule is a composite summary of production property acquisitions made by Group 1 Respondents during the years 1940-1954. It consists of information filed by such respondents in response to the data request of the Municipal Gas Group.

Column (2) indicates for each year (1940-1954) the number of companies which reported an amount for investment made in production property acquisitions. The amounts reported as applicable to producing leases are summarized in Column (3). The amounts reported as applicable to non-producing leases are shown in Column (4), and composite amounts applicable to properties other than producing or non-producing leases are shown in Column (5). The totals reported for investment in acquisitions are shown in Column (6).

To the extent that gas reserve data applicable to the reported acquisitions were reported by Respondents they are summarized in

[972]

Columns (7) and (8). The volumes of reserves reported as applicable to acquisitions are shown in Column (8). The number of companies reporting such reserve data is shown in Column (7).

Column (9) has been included so as to show the amount of investment applicable where both reserve data and acquisition cost were reported by the Respondent. In other words, the reserves shown in Column (8) relate to the amount of investment shown in Column (9), rather than the total investment shown in Column (6).

The total investment reported for production property acquisitions by Group 1 Respondents during the years 1940

to 1954, inclusive, amounted to $50,014, 914 (total of Column (6)). The gas reserves reported, aggregating 4,982,-649 Mmcf, related to $31,152,982 of such investment.

The number of Respondents which reported one or more acquisitions during the period covered by the responses aggregated 13.

Although 12 respondents reported reserve data relating to acquisitions, such data were reported for only a portion of the acquisitions by some of the respondents.

Q. Schedule 2 includes two footnotes. Do these require any explanation in addition to those given on the schedule? A. The footnotes call attention to acquisitions effected by merger with affiliates. These amounts to which the footnotes apply do not appear to have been included in investments in production properties reported by any Respondent in years previous to the date of acquisition shown on Schedule 2.

Q. What is shown by Schedule 3? A. This schedule is a summary of the responses received from Group 1 Respondents reporting the costs and volumes applicable to gas reserves sold or transferred by such companies during the years 1940 to 1962, inclusive. The book costs applicable to the dispositions reported aggregated $100,118,401, as shown by the amounts entered in Column (4).

[973]

The total of the volumes reported in connection with the dispositions of gas reserves amounted to 6,950,903 MMcf as shown by Column (3). The reserve data applicable to a small portion of the dispositions were not reported by respondents. The book costs applicable to the volumes reported aggregated $99,938,939, as shown by Column (5).

As indicated by footnote 3, one respondent in each of the years 1958 and 1960 sold gas reserves to which zero book cost was attributed. Such sales aggregated only approximately 16,000 Mmcf.

A total of 14 Respondents reported sales of gas reserves. The six reporting the largest sales account for 97.4% of the

total sales on a book cost basis, and 86.7% of the total on a volume basis.

Q. Can you state the extent to which the sales of gas reserves which are summarized on Schedule 3 were made to affiliates? A. Not precisely. This information was not specifically mentioned in the Municipal Gas Group data request. Based on information reported, however, it is known that a great portion of the total sales, more than 80%, was made to affiliates. One such transaction alone, in 1961, represented approximately $69,000,000 of net book cost applicable to off-system properties. It appears from information obtained from Respondents that two of such sales of reserves mentioned in the Municipal Gas Group's data request, namely those made by Northern Natural Gas Company and Cities Service Gas Company, consisted of properties having an aggregate book value in excess of $12,000,000.

Q. Are the gas reserves which were sold by Northern Natural Gas Company and Cities Service Gas Company, respectively, still owned by affiliates of those companies? A. No. In fact, the present owners are not even respondents in this proceeding.

Q. Did the Municipal Gas Group attempt to obtain data concerning the production company affiliates of Northern Natural Gas Company and Cities Service Gas Company applicable to the period, in each

[974]

instance, beginning with the transfer of production properties to the affiliate and ending at the time the affiliation was broken? A. Yes. This was in the Municipal Gas Group data request.

Q. Was the Municipal Gas Group successful in its attempt to obtain such data? A. No. Neither the present owners nor the pipeline respondents has furnished the data requested, even though this request has been repeated in correspondence carried on subsequent to making the initial request.

[974]

Q. Would you explain what is shown on Schedule 4? A. This schedule is a composite summary of Exploration and Development Operations Costs and Expenses for each of the years 1940 to 1954, inclusive, portraying data reported by Group 1 Respondents in response to the data request of the Municipal Gas Group. The amounts reported for such costs and expenses have been classified in Columns 3, 4, 5 and 6, among the following four categories:

Dry Holes and Test Wells
Lease Write-Offs
Rentals
Other

The totals of such costs and expenses for each of the years covered by the schedule are shown in Column (7).

In Column (2) of the schedule is shown for each year the the number of companies reporting this item of expense. The number of reporting companies in the Group 1 Respondents varied between 15 and 18.

Q. What is the total amount reported by 15 companies for the year 1940, as well as the total reported by 17 companies for the year 1954? A. As shown in Column (7) the total amount of Exploration and Development Operations Costs and Expenses reported by 15 pipeline companies for the year 1940 was $2,102,050. For the year 1954 the total amount reported by 17 companies for this class of expense was $12,673,199.

[975]

Q. What are the totals shown by Schedule 4 for the various expense categories? A.

Dry Holes and Test Holes	$31,783,981
Lease Write-Offs	6,759,264
Rentals	39,161,081
Other	3,448,831
Total:	$81,153,157

Q. Do these amounts include expenses incurred by producers affiliated with pipeline companies? A. No. Such

producers are included in separate groups. The corresponding data for Group 3 Respondents is shown on Schedule 9.

Q. Would you state whether the total amount of $81,-153,157 represents the total expenditures during the years 1940 to 1954, inclusive, made by pipeline companies for exploration and development costs and expenses in the United States? A. No. It represents only a portion of the total expenses of that type incurred directly by pipeline companies in the United States during the years 1940 to 1954, inclusive.

Q. What source of information did you use in reaching that conclusion? A. Principally the Statistics of Natural Gas Companies published by the Federal Power Commission. Data for the years 1940 and 1941, however, are not available from that source.

Q. What is the magnitude of Exploration and Development Costs published in Statistics of Natural Gas Companies for the years 1942 to 1954, applicable to companies which were not included in arriving at the composite costs shown on Schedule 4? A. Such amounts varied from approximately $2,300,000 to $5,100,000 annually. The total for the 13-year period from 1942 through 1954 amounts to approximately $46,000,000. In determining these totals all amounts of less than $5,000 reported for a given year were disregarded.

Q. What is the magnitude of the number of companies whose exploration and development expenses were included in arriving at the totals

[976]

which you have just indicated? A. The number of companies varied from year to year, in a range of 19 to 31. In all except three years the number was 24 or less.

Q. Referring to Schedule 4, it is noted that the level of total expenses shown thereon moved upward sharply in 1947 as compared with earlier years. Would you please explain what occurred to bring about this increase? A. One respondent which reported total exploration and develop-

[976]

ment expenses amounting to $1,214,730 for 1947, reported no amount for this item prior to that year in response to the Municipal Gas Group data request. Several other respondents reported sizable increases in 1947 as compared with the prior year.

Q. It is noted from examining Schedule 4 that the total of exploration and development expenses more than doubled between 1947 and 1954. Was there any difference in the list of respondents reporting exploration and development expenses for 1954 as compared with 1947? A. Yes. However, the difference is not great and has practically no significance. Two respondents which reported relatively small amounts of exploration and development expenses for 1947 reported none for 1954. One respondent which reported none of such expenses for 1947 reported a small amount for 1954.

Q. What accounts for the substantial increase between 1947 and 1954? A. With respect to the 16 Group 1 Respondents which reported exploration and development expenses for both the years 1947 and 1954, respectively, eleven thereof reported substantial increases, while five reported decreases or no significant change.

Q. Your attention is directed to the Staff's composite summaries of Exploration and Development Operations Costs and Expenses reported by Group 1 companies for the years 1955 to 1962, inclusive. Are the data shown in Schedule 4 comparable to the Staff's composited data relating to exploration and development expense? A. Generally speaking, yes, in the sense that the portrayal of the general trend of such expenses incurred by pipeline producers

[977]

as a group does not require absolute precision and therefore would not be distorted by the minor differences in the list of companies composited. This conclusion also appears to be justified on the basis of amounts reported for these expenses as shown in the FPC published Statistics of Natural Gas Companies.

Q. Please explain Schedule 5. A. This schedule shows, for each of the years 1940 to 1954, the composite net acres and costs transferred from non-producing to producing property, as reported by Group 1 Respondents.

The number of companies for each year which reported the information as to both the net acres and costs included in transfers is shown in Column (2). The net acres and costs so reported by such companies are shown in Columns (3) and (4), respectively. Eight companies reported these data for 1940, compared with fourteen which reported for 1954.

In certain years, one or two companies omitted either acreage or cost information from their responses. These instances are summarized in Columns (5) to (8) inclusive. The omissions are relatively insignificant.

The total net acres and cost reported are summarized in Columns (10) and (11).

Q. What is the total transfer of net acres reported by Group 1 Respondents for the period 1940-1954? A. As shown by the total of Column (10), that sum is 1,660,622 net acres.

Q. What is the total transfer of cost from non-producing to producing property, reported by Group 1 Respondents for the period 1940-1954? A. As shown by the total of Column (11) that sum is $10,049,793.

Q. What types of leases comprise the transfers of acreage summarized in Schedule 5?

[978]

A. The transfers were reported as consisting principally of "gas only" leases. The transfers reported for categories other than "gas only" were insignificant in relation to the totals.

Q. Please explain what is shown on Schedule 6. A. This schedule shows for each of the years 1940 to 1957, inclusive, the volumes of gas produced by pipeline company respondents, and the affiliated producers classified in Group 3, respectively. The data shown on the schedule were obtained through responses to the Municipal Gas Group data

request submitted by respondents. The volumes of gas (stated in Mmcf) reported by pipelines as produced from their own reserves are shown in Column (3). The volumes reported as produced by Group 3 affiliated producers are shown in Column (5). The number of respondents reporting the data is shown in Columns (2) and (4), respectively.

Q. How many pipeline respondents are shown as producing gas from their own reserves in 1940? A. Twelve.

Q. What was the volume of production? A. 255,448 Mmcf.

Q. What volume was produced by pipeline respondents in 1957? A. 678,128 Mmcf.

Q. What number of companies accounted for this volume? A. Twenty.

Q. Please summarize the comparable data for the affiliates shown on Schedule 6. A. In 1940 one affiliated producer reported production of 148,709 Mmcf. In 1957 five affiliated producers reported 286,179 Mmcf.

Q. What is the total production of gas by pipelines and Group 3 affiliates for the 18-year period 1940 to 1957, inclusive, as shown by Schedule 6? A. Approximately 13 trillion cubic feet. Some 9.4 trillion was produced by pipelines directly and 3.6 trillion by affiliates.

[979]

Q. Please explain Schedule 7. A. This schedule shows historical data pertaining to gross production related investment and gas reserves reported to the Municipal Gas Group by pipeline affiliated producers classified in Group 3. Its scope and content are similar to those of Schedule 1 which has already been explained as a composite of comparable data reported by Group 1 pipeline respondents.

Columns (3) to (5) inclusive, of Schedule 7, show gross investment data as reported for each of years 1940 to 1961, inclusive. As explained in footnote 1, Exploration and Development Investment data were reported for only the years 1940 to 1954, inclusive, to the Municipal Gas Group.

The volumes of gas reserves reported as related to the investment shown in Column (5) are shown in Column (6) for the years 1940 to 1957, inclusive.

In some instances investment was reported without reporting the gas reserve data requested. This type of reporting is summarized in Columns (7) to (10) inclusive.

Column (12) shows the total reported to the Municipal Gas Group for gross investment in production, exploration and development properties. It represents the sum of amounts shown in Columns (5) and (10), respectively.

Q. What are the more significant increases in investment, reserves and number of companies reporting during the periods shown on Schedule 7? A. For 1940 two pipeline affiliated producers of the Group 3 classification reported approximately $79,000,000 for gross investment in production facilities. For 1961 six producers of that class reported approximately $374,000,000 for gross production investment. With respect to gross Exploration and Development Investment, one respondent reported $7,719,000 for 1940 and five

[980]

respondents reported $32,230,000 for 1954.

The gas reserves reported for 1940 by one respondent amounted to 2.4 trillion cubic feet. As of the end of 1957, five Group 3 respondents reported reserves of 4.8 trillion cubic feet.

The increasing trend in gross investment, gas reserves and number of companies is apparent from the face of the schedule, with the volume of reserves being nearly level for the years 1954-1957.

Q. Please explain Schedule 8. A. This schedule shows composite data for the years 1940 to 1954, inclusive, relating to production property acquisitions made by Group 3 respondents, based on responses to the Municipal Gas Group data request. Columns (3) to (6), inclusive, show the amounts of investment made in such acquisitions with total investment being broken down among producing leases, non-

[980]

producing leases and "other". Columns (7) to (10), inclusive, show information relating to the volumes of gas reserves obtained through such acquisitions to the extent such information was reported to the Municipal Gas Group.

Column (11) shows that portion of the total acquisition investment reported for any given year which is related to the gas reserves reported as summarized in Columns (8), (9) and (10). Such investment data relate to liquid reserves acquired as well as gas. Although the total acquisitions reported amount to $37,854,568, as shown by Column (6), the total gas reserves reported, aggregating 158,358,000 Mcf, were associated with investments aggregating $26,585,-816, as shown by Column (11).

Footnote 2 calls attention to what appears to be an obvious failure on the part of Lone Star Producing Company to report an acquisition in 1943 of gas reserves transferred to it by its parent, Lone Star Gas Company.

[981]

Q. Please explain Schedule 9. A. This schedule is a summary of Exploration and Development Operation Costs and Expenses for each of the years 1940 to 1954, inclusive, showing composite data reported by Group 3 respondents, consisting of affiliates of pipeline companies, in response to the data request of the Municipal Gas Group. The format of this schedule is precisely that of Schedule 4, concerning which I have testified.

The schedule shows that the number of respondents reporting in this group increased from two in 1940 to five by 1954, the last year for which data were obtained through the Municipal gas Group request. The years 1955 to 1962, inclusive, are covered by the Staff questionnaire, FPC Form 50.

Q. What does Schedule 9 disclose with respect to increases in Exploration and Development Costs? A. For 1940 the total Exploration and Development Costs reported by the two respondents of this class amounted to $1,275,-444. For the year 1954 the comparable amount reported

by five respondents amounted to $12,680,436. Substantial increases occurred in each category of the expense breakdown on Schedule 9. The greater portion of the substantial increases during the period 1940 to 1954 shown in the "Other" column represents increases in geological and geophysical expenses.

Q. What is the total amount of Exploration and Development Costs for the years 1940 to 1954, inclusive, reported by Group 3 Respondents? A. As shown by the total of Column (7) this amount is approximately $76,000,000 for the 15-year period.

Q. Please explain Schedule 10. A. This schedule shows, for each of the years 1940 to 1954, the composite net acres and cost transferred from non-producing to producing property, as reported by Group 3 Respondents.

The number of companies for each year which reported the information as to both the net acres and costs included in transfers, is shown in Column (2). The net acres and costs so reported by

[982]

such companies are shown in Columns (3) and (4), respectively. One respondent omitted acreage data but reported cost information which has been summarized in Column (5).

One company reported data for 1940, compared with three which reported for 1954.

* * *

[983]

PROPOSED DIRECT TESTIMONY OF
MELWOOD W. VAN SCOYOC

Q. Please state your name. A. Melwood W. Van scoyoc.

Q. Where do you reside? A. Washington, D. C.

Q. What is your business? A. I am President of the firm of Van Scoyoc & Wiskup, Inc., Public Utility Consultants with offices at 1735 K Street, Northwest, Washington, D. C.

[983]

Q. Please outline your educational background? A. I was graduated from Oregon State College in 1927 with the degree of Bachelor of Science in Electrical Engineering. Subsequently I took courses in accounting from the Oregon Institute of Technology and the Walton School of Commerce.

Q. What has been your experience in the field of public utility regulation? A. I have been engaged continuously in public utility regulatory matters since my graduation from college, with the exception of thirty-nine months in World War II, during which I served as a Captain in the United States Army.

[984]

My first employment was by the then named Public Service Commission of Oregon as Assistant Engineer. I held this position from June 20, 1927 until January 1, 1930.

From January 1, 1930 until April 1, 1931, I was in the employ of the Portland Electric Power Company as Assistant Valuation Engineer. I returned to the Oregon Commission Staff on April 1, 1931, in the capacity of Statistical Engineer, which position I held until April 1, 1935. Upon the reorganization of the Commission Staff I was appointed Utility Auditor and head of the Department of Finance and Accounts. On July 1, 1936, I was given the title of Chief Accountant.

In these several positions with the Oregon Commission my duties embraced the inventorying and pricing of public utility property; audits of property records and other books of account; analyses of rates and tariffs; formal rate and other investigations of utilities; auditing of annual reports of railroads and utilities; preparation of rules and regulations, uniform accounting systems, annual report forms, and statistical publications; and the making of analyses and recommendations to the Commission concerning depreciation rates, issuance of securities, mergers, purchases and sales of utility property, transactions between affiliates, rates of return, annual utility budgets, and other matters. I also acted as Trial Examiner in a number of cases. During the major

period of my employment by the Oregon Commission my duties involved the supervision of other staff members.

[985]

On November 14, 1938 I entered the employ of the Federal Power Commission as Assistant Chief of the Division of Original Cost. Thereafter I was appointed Acting Chief of that Division, and on July 1, 1939 became its Chief. I continued in that capacity until entering upon active military duty in June 1942. The Division of Original Cost was charged with the responsibility of verifying the original cost and reclassification studies submitted by approximately 300 public utilities and natural gas companies in compliance with the Commission's Uniform System of Accounts.

Following my return from military service in September 1945, I was appointed Assistant Chief of the Commission's Bureau of Accounts, Finance and Rates, which position I held until my resignation on July 23, 1954. In that position I exercised general supervisory duties with respect to all of the functions of that Bureau, including matters dealing with natural gas and electric rates, certificates of public convenience and necessity, accounting and depreciation practices, security issues, rate of return and FPC statistics.

In addition to these supervisory duties I actively participated in a number of the more important proceedings involving rates, certificates of public convenience and necessity, and accounting matters which were before the Commission during this period of approximately nine years.

Since my resignation from the Federal Power Commission I have been continuously engaged in consulting work in the public utility field, chiefly in connection with rate proceedings

[986]

before the state commissions and the Federal Power Commission. Our clients have included governmental agencies, state regulatory commissions, municipalities, public utilities, REA Cooperatives, industrial customers and trade organizations.

Q. Mr. Van Scoyoc, did you testify before the Oregon Commission and the Federal Power Commission as a staff member? A. Yes, I testified on numerous occasions before the Public Utilities Commissioner of Oregon in matters dealing with rates, security issues, mergers, accounting practices, depreciation rates, affiliated company transactions, and other matters. While a member of the FPC Staff I testified in a number of proceedings before that Commission, dealing with pipeline company rates, original cost and reclassification matters, mergers and accounting practices. I also testified before the Securities and Exchange Commission in a Section 77(b) proceeding, when I was a member of the Oregon Commission Staff.

Q. Since the establishment of your consulting practice, to what extent have you testified in proceedings before state commissions, the Federal Power Commission, other regulatory commissions and the Courts? A. I have testified before the Arkansas, California, Colorado, Georgia, Iowa, Louisiana, Maine, Maryland, Michigan, Mississippi, North Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, Tennessee, Washington and West Virginia Commissions in 44 rate and other proceedings. I have also testified before the Federal Power Commission in 35 proceedings involving natural gas and electric rates, applications for certificates of public

[987]

convenience and necessity, and other matters. I have also testified before the Federal Communications Commission, the Canadian Royal Commission on Energy, The Board of Transport for Canada, the Province of Alberta Public Utility

Board, the Province of Quebec Electricity and Gas Board, two Federal District Courts and one state Superior Court.

Q. In addition to the cases where you have given testimony, have you also acted as a consultant in public utility matters for clients, which did not involve your giving testimony. A. Yes, sir, our firm has made investigations and has represented clients in numerous proceedings before state Commissions and the Federal Power Commission involving rates and other matters.

Q. Have you published any articles or delivered any papers concerning public utility regulatory matters? A. I have delivered a number of papers before utility organizations and other groups, some of which have been published.

Q. Have your professional qualifications been recognized by any state? A. Yes, I am a Registered Professional Engineer of the State of Oregon and of the District of Columbia.

Q. Are you a member of any technical or professional societies or organizations? A. Yes, I am a member of the District of Columbia Society and the National Society of Professional Engineers, and also of the American Accounting Association, the National Association of Accountants and the Federal Government Accountants Association.

[988]

Q. Mr. Van Scoyoc, on whose behalf is your testimony in this proceeding being presented? A. The Municipal Gas Group of intervenors consisting of the Cities of Chicago and Denver, the Memphis Light, Gas and Water Division and the American Public Gas Association.

Q. Would you outline the experience which you have had concerning the regulation of the rates of pipeline companies which either directly or through affiliates own and produce natural gas reserves. A. My interest in this question goes back to the early gas rate cases of the Federal Power Commission prior to and during the earlier years of World War II, although I was not directly concerned in the

[988]

trial of such cases. I had a more direct responsibility in the in the Natural Gas Investigation conducted by the Federal Power Commission, known as the Docket G-580 Investigation, which commenced in 1945 and concluded in the latter part of 1947. At about the same time legislative efforts were being made to amend the Natural Gas Act so as to forbid the use of the cost method of regulation with respect to the production of natural gas by pipeline companies and affiliates. I was directly involved in that controversy as a member of the Federal Power Commission staff and made a number of economic analyses and statistical compilations dealing with the subject. Later in connection with the Kerr bill inbill in the 81st Congress, which was designed to exempt independent gas producers from Federal Regulation, I made further studies of this question as a member of the FPC staff. I actively participated in rate cases before the Federal Power

[989]

Commission, where the ratemaking treatment of pipeline Company production was involved, such as the *Pittsburgh and West Virginia Gas Company, Kentucky-West Virginia Gas Company*, 7 FPC 112, *Panhandle Eastern Pipe Line Company*, 13 FPC 53, *Northern Natural Gas Co.*,11 FPC 123, and the *El Paso Natural Gas Company*, 13 FPC 421 rate cases. Since leaving the Commission, this issue has been given a good deal of study by me in connection with several pipeline company rate cases before the Federal Power Commission and in one case before the Arkansas Public Service Commission.

Q. Have you participated in proceedings before the Federal Power Commission involving rates or certificates of public convenience and necessity of companies classified as independent producers? A. Yes. I participated as a consultant and witness in a number of such proceedings including *Phillips Petroleum Company*, Docket No. G-1148, et al., *Union Texas Oil & Gas Corporation*, G-11563, *Champlain Oil & Refining Co.*, G-9277, et al., *Texaco-Seaboard, Inc.*,

C161-118, *H. L. Hunt Oil Co., et al.*, G-19086, *Gulf Oil Corp., et al.*,CP60-43, and the South Louisiana Area rate case, AR 61-2.

Q. Would you state briefly the present policy of the Commission concerning pipeline company and affiliated company production, as you understand it? A. This policy is known as the traditional cost of service method of rate regulation. Under this method the pipeline company is entitled to charge rates which will enable it to recover its reasonable costs of operation and to provide a fair return on the investment which is devoted to public service. Thus, the

[990]

reasonable costs, including capital costs, incurred in the production of natural gas by the pipeline company or its affiliate and the amounts it pays other producers or pipelines for gas are recovereable through rates.

Q. Has the Commission's use of the individual company rate base approach for regulation of the price allowed for pipeline and affiliated produced gas proved to be workable and feasible? A. Yes, It has proved completely workable and feasible to ascertain the cost of producing natural gas of pipeline companies and affiliates by use of cost accounting processes. It has also been feasible to make a reasonable appraisal of the risks of the gas production business and to provide compensation for these risks in the rate of return. We know that the production of gas requires a large capital investment in relation to annual income. Therefore, fixed charges constitute a large share of annual production costs. In this respect gas production is quite similar to the transmission and distribution business of pipeline companies and public utilities. For example, the ratio of production net investment in the U. S. of Appeadix B and C producers in Docket No. AR61-2 for the year 1960 is 2.08 times the revenues from such production operations. This ratio is comparable to the ratio of 2.03 times revenues for natural

[990]

gas pipeline companies and 3.6 times revenues for Class A and B electric utilities in the same year.

There are, of course, recognizable differences between the operations and economics of gas and electric distribution utilities, gas pipeline companies and gas producers. But these

[991]

differences are not so great as to make the use of the cost of service method inapplicable to gas production. While these differences call for the application in some instances of different techniques and procedures, the same regulatory principles apply and reasonable, practical solutions are possible. So far as pipeline and affiliate production is concerned, solutions have already been found by the Commission for the problems created by these differences.

Q. Has the Commission ever departed from the traditional cost of service in its treatment of pipeline produced gas for ratemaking purposes? A. Yes, in the cases of *Panhandle Eastern Pipe Line Company*, 13 FPC 53, and *Olin Gas Transmission Co.*, 17 FPC 695. The *Panhandle* decision in this respect was reversed by the United States Court of Appeals, 230 Fed 2d 810, Certorari denied, 352 US 829.

Q. What is your understanding of the test that would have to be met if the Commission should contemplate allowing amounts for pipeline or affiliated produced gas in excess of those which would result from the use of the conventional rate base method? A. Irrespective of the purpose of such an allowance, whether it be to encourage exploration and production activities, or for other reasons, the test would be whether such an excess is in fact needed, and is no more than is needed, for whatever purpose it would presume to accomplish.

Q. Are the financial risks of independent producers of natural gas and those applicable to production by a pipeline or its affiliate the same?

[992]

A. No.

Q. What are the principal differences between the financial risks of independent producers of natural gas and those applicable to production by a pipeline or its affiliate? A. Pipeline companies have an assured market for the gas which they and their affiliates discover. Moreover, they have the opportunity to recover all of the costs of production including a fair return. On the other hand, the independent producer has to find a market for his gas once it is discovered and he may not be able in every instance to recover all of his costs, including a fair return, under the price he is able to obtain in the particular market available to him at discovery. Although in today's gas supply-demand situation the difficulty of finding a market is not nearly as difficult as at one time in the history of the gas industry, it is nevertheless of some considerable concern to the independent producer. Since the pipeline companies have a steady source of income from their pipeline operations they are in a position to accept fluctuations in success or failure in the exploratory phase of their business. Under the Federal Power Commission's treatment of exploration and development expenses in rate proceedings the current losses of the exploratory program are charged to the ratepayers. This policy has the effect of minimizing the financial risk to the pipeline of exloration so far as sales of natural gas in interstate commerce are concerned. Under such ratemaking treatment, any risks and uncertainties due to exploration, together with the other risks of the business, are merged together and are compen-

[993]

sated for by the allowed fair rate of return.

Q. How do the fair rates of return allowed pipeline companies having production operations compare with the rates of return which the Commission and the Examiners have allowed in producer rate cases? A. The highest rate of

[993]

return which the Commission has allowed a pipeline company on its combined production and transmission operations is 6.5%, whereas the rate of return which it has so far allowed independent producers in an area rate case, namely the Permian Basin case, AR61-1, is 12%, 34 FPC 200; 215. The FPC staff recommended a rate of return of 9.5%, in which it was joined by the California Public Utilities Commission and the Distributor Intervenors, whereas the producers claimed rates of return of 16-18%.

In the South Louisiana area rate case, AR61-2, the Examiner found the fair rate of return to be 12%, but included an additional incentive allowance in the price determined for new gas. In oral argument before the Commission the FPC Staff apparently took the position that 10.5% would be at the upper limit of reasonableness. The Associated Gas Distributors apparently did not except to 12%. The Municipal Gas Distributors recommended 9.5%, while the Producers claimed a rate of return of 16%.

Pipeline companies usually finance a large share of their capital requirements through issuance of debt securities, while independent producers generally have little or no debt in their capital structure. Debt financing has low cost and income tax advantages, both of which contribute to lower pipeline rates.

[994]

It is obvious from the foregoing that pipeline companies are considered to have significantly lower capital costs than the independent producers. The advantage to gas consumers of low cost capital apparently would be discarded by the use of area rates for pipeline company and affiliate production of natural gas transported and sold in interstate commerce. Moreover, pipeline producers which could not earn a reasonable rate of return on their net investment in production facilities under area rates might experience increasing capital costs which would be a burden on consumers.

Q. Would the ownership of gas reserves insure the carrying out of the public utility functions of a natural gas pipe-

line company in a more efficient and economical manner than if such company relied on gas purchased under contract? A. No, sir, not in my opinion. I believe a natural gas pipeline company can function efficiently and properly serve the public without ownership of any gas reserves whatsoever, providing it has the contractual right to obtain the gas as it is needed to meet its market requirements. This is demonstrated by the fact that there are many natural gas companies successfully engaged in the transmission or distribution of natural gas, who own no gas reserves and depend 100 per cent for their gas supply upon gas purchased under contract from independent producers or pipeline companies.

Q. Do you agree that the ownership of gas reserves provides some flexibility in operation which is not possible in the case of purchase gas contracts?

[995]

A. I would agree that if the pipeline company is the sole owner of a gas field, which situation is extremely rare, such ownership could permit operational flexibility which would be difficult to secure under the current type of gas purchase contract, provided the pipeline company has agreements with its royalty owners to produce or not to produce at the option of the pipeline company. Where there are several producers in a gas field, gas must be produced rateably otherwise some producers would secure more than their equitable share of the gas reserve and other producers would be penalized by drainage. The pipeline company owning reserves in a field with other producers cannot produce such reserves to meet its market demands without regard to the production of the reserves owned by other producers in the field, including those which are under contract to it. State proration laws and rateable-take statutes make it virtually impossible for producers to operate their wells in disregard of the correlative rights of other producers in the field. Admittedly, the realm of flexibility through reserve ownerships must fall within the limits of such orders which apply

[995]

as well to all producers in the field. For these reasons I do not view the possibility of flexibility stemming from reserve ownership to be of particular advantage to customers by furnishing more reliable service at a lesser cost. No one, so far as I know, has ever demonstrated that the claimed lack of operational flexibility stemming from reliance upon gas purchase contracts is costing customers higher rates or is resulting in poor service.

[996]

As I previously testified, many natural gas pipeline companies have operated for years and are now operating with their entire gas supply being furnished under contract by independent producers or other pipeline companies. No one, so far as I know, has contended that their operations are not conducted satisfactorily, economically and efficiently or that their customers are not receiving uniform and reliable service at reasonable rates because the pipelines do not own gas reserves. Based upon my knowledge of the operation of natural gas companies, I do not believe that the claimed advantage of operational flexibility flowing from ownership of natural gas reserves provides any valid justification for the encouragement of pipeline company reserve ownership through the use of the area rate approach.

Q. Do you believe that the ownership of gas reserves by pipeline companies and their affiliates is desirable in the interest of gas consumers and that natural gas companies should be encouraged and induced to own their gas supply rather than to rely upon gas purchase contracts? A. As a matter of general policy I would agree that ownership of gas reserves and production facilities is desirable in the same sense that ownership of the gas transmission lines is desirable. The same is true of the ownership by electric utilities of their generating stations, bus lines of their buses and railroads of their freight cars and lines. But for one reason or another, some utilities purchase the commodity they sell and lease facilities from others.

[997]

However, the necessity for ownership of gas reserves is no more compelling than is the ownership of any other property used in utility service. In my opinion, there is no more justification for the allowance of profits over and above a fair return in order to encourage gas reserves ownership than there is to allow an excessive rate of return in order to encourage a pipeline company to expand its transmission system to serve a particular community or area or to encourage an electric utility to build a hydro-electric generating plant in lieu of a steam-electric generating plant so that falling water may be put to a beneficial use or that fossil fuel be conserved.

I do not believe that natural gas companies need be or should be encouraged to own gas reserves through regulatory commission action which departs from the traditional cost method of regulation. The area rate approach would produce unnecessarily excessive rates of return for some companies with low cost production and inadequate rates of return or losses for high cost producers.

Whether or not a pipeline company should engage in production operations and the extent thereof is a decision for management. The incentive which prompts the commitment of capital to a regulated enterprise is the opportunity to earn a fair return on such capital.

The role of regulation is simply to achieve an equitable balancing of the investor and consumer interests regardless of whether management decides to engage in exploration and production to supplement current purchases from independent pro-

[998]

ducers or in lieu of future purchases or decides to rely upon independent producers or other pipeline companies for their entire gas supply.

* * *

[1014]

FELIX I. SCHAFFNER

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

* * *

[1053]

[CROSS EXAMINATION]

* * *

BY MR. REIFSNYDER:

* * *

Q. In Appendix A, page 1 attached to your testimony, and it appears I believe at transcript 503, you reflect capital ratios and capital costs per pipelines as at December 31, 1962.

[1054]

You will agree that capital costs have risen substantially since 1962? A. Long-term debt costs have risen; preferred stock costs have risen; common equity costs, depending on the position that you take with respect to the method of measuring them, may have risen or fallen. By that I mean the stock market has gone up since 1962 very considerably, people seem to be more interested in buying common stocks, frequently they buy common stocks that have very little earnings, if any, and, therefore, I assume they are paying a much higher price for the earnings of common stocks.

I saw a group of common stocks the other day, which I will be glad to show you later, which have an earnings average—price-earnings ratio of over 93 times. The inverse of that would be the earnings-price ratio, which would be less than one percent.

* * *

[1070]

BY MR. REIFSNYDER:

Q. Doctor, is it not true that since pipelines have traditionally been regulated on a cost of service basis they have been permitted to expense dry hole costs and thus have, in

[1071]

effect, charged those costs to their customers? A. Well, speaking not as an expert on this subject but as someone who has read a great deal of testimony on the subject, I would say the answer is yes.

Q. Have you not in the past taken the position in individual company rate cases that such certainty of recoupment of dry hole and other properly incurred production and exploration costs result in the lowering of the risk of natural gas pipelines' production operation? A. I don't know as I have been quite as forthright as you have expressed, or paraphrased my opinion, but it certainly seems to me to be a help.

Q. You have, in effect, then, used this lowered risk as a justification for granting a pipeline a lower rate of return on its own production operation, have you not? A. The main reason why pipelines have gotten a lower rate of return on their operations is because, as I have said before several times, of the fact they have a large percentage of their capital in the form of senior capital, debt capital and preferred stock capital, and this capital is less expensive than common equity capital. That is the main burden of my testimony; that is the main difference between these companies and independent producers.

* * *

[1085]

[BY MR. ROSS:]

* * *

Q. Would it be fair to say that you don't get the same amount of leverage in issuing a dollar of preferred that you

[1085]

do in acquiring a dollar of long-term debt, or would it not? A. Well, you raise a very interesting point. I think you do get as much leverage as far as rate of return is concerned. You don't get the same leverage as far as taxes are concerned. But there are certain institutional investors which have a choice between investing in bonds or highgrade preferred stocks, and if they buy the preferred stocks, 85 percent of the dividends on those stocks are tax-free to the buyer. Therefore, an institutional investor is paying virtually something like seven percent taxes on preferred stock as contrasted with 48 percent which it would pay if it bought bonds. For this reason there is a big demand among institutional investors for preferred stocks.

* * *

[1091]

Q. Do you have any information that would lead you to an opinion as to why major oil companies don't take advantage of the leverage involved in debt financing but tend to finance out of retained earnings? A. I would like to refer you to Donaldson's book on corporate debt capacity issued by the Harvard Business School on this whole subject.

Q. This book right here, sir? I believe this is it. A. Yes, that is the one.

Q. As I understand the major thesis of that book, and this would really bring Mr. Haworth to his feat, I think, is that they are foolish, they don't know what they are doing.

MR. LEITHEAD: I feel like it should bring me to my feet, too. What is in the book?

BY MR. ROSS:

Q. It is a fair assumption, isn't it, that they are concerned about the fact that they might hit a lot of dry holes and have to pay that debt back on schedule out of those dry holes? A. Well, they certainly tell us all about it. There is one point, however, that maybe I might mention, and that is bonds are tax deductible, deductible before

taxes in paying income. If it is true that independent producers do not pay

[1092]

income taxes in any event, then they do not have the same incentive to issue bonds that would be the case with a company which has to pay taxes on its income and can save taxes by issuing bonds or issuing a larger portion of bonds as its capitalization.

* * *

[1096]

PRESIDING EXAMINER: Can you tell us whether the example given to you by Mr. Ross is something that you can recognize? Do you know situations where five percent of the equity capital

[1097]

is allocated for research and exploration?

THE WITNESS: No, sir, I do not, and one of the basic things about financing corporate enterprises engaged in more than one type of enterprise is that since you can not make dollars radioactive, you have no way of determining where the dollars came from or where they went to. Therefore, you have no way of determining what kind of dollars you had in any particular form of activity. However, we do have some prospectuses, and I have them right here, that indicate—for example, here is one dated May 1, 1965, Columbia Gas System, 4.58 percent debentures of May 1990, 40 million dollars worth, in which they indicate that the funds will be used in part for production.

* * *

[1113]

* * *

Q. [By Mr. Ross] Dr. Schaffner, I believe you testified elsewhere that independent producing companies have shown a very wide range of earnings and would continue to have a very wide range of earnings under an area rate regulation method; is that not the case? A. That is right. In other words, regulation under area pricing does not regulate the return; it merely sets the price, and under that price the company may make much more than the rate which was used in determining the price.

* * *

[1133]

[BY MR. ALBRECHT:]

* * *

However, we have found that area pricing has some other advantages in that it gives the efficient producer an opportunity to earn a return above that which was formerly used for the industry as a whole, which return he can then keep and this gives an incentive to efficiency. This is one of the points I make in connection with the use of the possibility of area pricing of pipeline produced gas for leases acquired after the date of the order.

* * *

[1703]

* * *

[Witness Bass] * * * Purchases," so forth, "Summary, Continental U.S., Years 1955 Through 1962." Under a heading "Producing Leases," line 6 is termed "Total Producing Leases," and above it are the items on line 1, Leaseholds; on line 2, Lease and Well Equipment; on line 3, Intangible Development Cost; on line 4, a subtotal for Lease and Well Equipment and IDC, totalling to line 6, Total Producing Leases. These are the items in the figures.

Q. [By Mr. Shibley] If a pipeline producer purchased a developed property from another owner, should it have

been reported on that particular schedule? A. That is my understanding of the instructions, yes, sir.

Q. Have you analyzed the schedules to determine whether there were in fact such assets purchased by pipeline producers during the period covered by Schedule No. 4? A. If there wasn't, I wouldn't have any numbers on my schedule.

[1704]

Q. You are saying in effect that all of the items in line 3 were developed leaseholds? A. I am saying that in answer to the Pipeline Production Questionnaire that the respondents—some respondents—I could maybe go back through my work papers and find out which ones if you are interested in it, since I say I have a number here, that some respondents reported data in answer to the questionnaire on these lines; yes, sir.

Q. Did you have occasion to ascertain which item or items was responsible for the 1960 figure of 204 million dollars charged to asset accounts for producing leases as compared with 23 million in 1959 and 15 million in 1961? A. We are on Schedule No. 3, sheet 1 of 1, sir?

Q. Yes, 1960, column (e), line 2, $204,788,133. A. I see the number. I believe your question was did I try to ascertain which company reported that?

Q. Yes, which were the major components of that. A. I can go back through my work papers and tell you I believe which company reported each figure to the summary, if you wish me to.

Q. Just do it for anything about 20 million dollars in that one figure. Have you been able to analyze that yet? A. I want to be sure I have got the right data here.

[1705]

I will go through the list of companies and try to pick it out. We had totaled it for all years to tie in, but I can go through the detail. For the year 1960—it would be simpler if I just read every one of them. Is it okay?

[1705]

Q. Tell me, Mr. Bass, what you are going to read. The companies that have the major asset acquisitions? A. I will just read all of them in 1960 that reported anything under that item? all right? And what they reported; all right?

Q. Fine. A. Would you like the name of the companies, also?

Q. Yes, sir. A. Atlantic Seaboard Corporation in 1960 reported expenditure charged to asset accounts for producing leases of $328,452. All of the figures that I will read after this will be the same item for other companies.

Q. I want to make a suggestion, Mr. Bass, in order to conserve your time. Will you limit it to items that exceeded three million dollars? A. I will try to; yes, sir.

El Paso Natural Gas Company, $37,671,932.

Tennessee Gas Pipeline Company, $159,499,381.

Texas Eastern, $6,959,065.

Those are all the figures exceeding three million dollars.

* * *

[2008]

[JOHN RAYMOND]

THE WITNESS: As the Staff's recommendation. The answer is yes, that is the point of presenting these tax deductions, to alert the Commission that there is this additional tax deductions available to the overall cost of service in any future rate case. If that is not taken into consideration, the spillover would fall through the crack, so to speak, and there would in effect be additional return to the pipeline producer.

BY MR. WHEATLEY:

Q. In other words, Mr. Raymond, if a spillover of such tax deductions which might exist were not recognized in computing transmission cost of service, would this eliminate a benefit which now accrues to gas consumers in a number of pipeline

[2009]

rate structure?

MR. SHIBLEY: Mr. Examiner, I object to this. This is not cross-examination.

PRESIDING EXAMINER: I agree with you, Mr. Shibley.

MR. LEITHEAD: Your Honor, may I ask if Mr. Wheatley's questions are confined to the pipeline production department of a pipeline company? Is that correct, Mr. Wheatley?

PRESIDING EXAMINER: The question has been overruled. But you might just as well explain it to Mr. Leithead.

MR. WHEATLEY: I think the question would be applicable to a production department of a pipeline. It would also perhaps be applicable to a situation where you have a consolidated return with an affiliate and you have a spillover.

PRESIDING EXAMINER: Do you have another question, Mr. Wheatley?

MR. WHEATLEY: Oh, did you overrule that?

PRESIDING EXAMINER: Yes.

[2097]

* * *

MR. DIETRICH: Well, I think that Your Honor has the responsibility which you have exercised time and time again to keep irrelevant and immaterial matter from cluttering this record, and I submit that any cross-examination that goes beyond the scope of this witness' presentation is just that.

Mr. Reifsnyder has kind of implied that he wants to develop a full record, and he is entitled to that right, and some how or other he might not have this right observed if he isn't allowed to go beyond the scope of this witness' presentation. I submit that is nonsense. I submit that Mr. Reifsnyder has a full opportunity to present his own case, and if he wants to go through the new gas cost component by component and show that each component affects only independent producers and not the pipelines and, therefore, Mr. Deutsch was wrong in using a summary of costs to develop his proposed recommendation, he has that opportun-

ity. I submit that all the components within the new gas cost already include pipeline data. I don't think that Mr. Reifsnyder can point to a single source document that does not include pipeline cost data as well as independent producer cost data in the new gas cost.

* * *

[2106]

* * *

NORMAN DEUTSCH

RESUMED the witness stand, and was examined and testified as follows:

* * *

[2160]

CROSS-EXAMINATION (Resumed)

* * *

Q. Mr. Deutsch, this morning Mr. Dietrich in attempting to clarify a question pertaining to whether or not pipeline data was included in the questionnaire data used by the Commission to determine pipeline operating costs mentioned three appendices of responses; do you recall that? A. Yes, I do.

Q. Do you know what those three appendices were, sir? Could you tell me what they were? A. I believe he referred to appendices that were attached to a Commission order. I don't have it before me.

MR. REIFSNYDER: Is that what you were referring to, Mr. Dietrich?

MR. DIETRICH: I think my statement on the record this morning was fairly clear what I was referring to. I was referring to the appendices that were used to collect data from the respondents, Appendix B was used to collect cost data from independent producers who had I guess gross sales or gross production,

[2161]

I am not sure which it was, of 10 million dollars or over, and Appendix C was used to collect data from smaller producers, and Appendix A was used to collect various operating data.

MR. REIFSNYDER: Well, cost data?

MR. DIETRICH: I think the producers down in Midland did request that data. It was collected in Schedule D of Appendix A.

BY MR. REIFSNYDER:

Q. With that explanation, could production operating costs have been computed from the Appendix A category, do you know? A. From what I have been reading from Opinion 468, even though the witnesses may have started with the data from the appendices, they always–not always, but the Commission may have adjusted those results from the questionnaire data and compared them to industry wide published data.

Q. Was that true of operating costs? A. That would be true. An adjustment was made to reflect national production of condensate and gas; so I would say that is true.

Q. We are talking of production operating expenses. A. That is what I am referring to, production operating expenses.

Q. Could production operating costs have been computed from the Appendix B category data.

[2162]

MR. DIETRICH: Irrelevant, Your Honor. The witness just explained what was done, not what could have been done.

PRESIDING EXAMINER: The objection is sustained.

MR. REIFSNYDER: I would like to follow it with one question for the record, Mr. Examiner.

BY MR. REIFSNYDER:

Q. Could production operating costs be computed from the Appendix C category data?

MR. DIETRICH: Same objection.

PRESIDING EXAMINER: Objection sustained.

BY MR. REIFSNYDER:

Q. Was data for any pipeline included in the Appendix B composite data?

MR. DIETRICH: As I recall before the luncheon recess, Mr. Reifsnyder inquired of me whether I wished to stipulate with that data. I suggested that I wished to check the data.

We would stipulate that no pipeline data were included in the composite data exhibits as presented by Witness Borwick in those proceedings.

* * *

[2163]

BY MR. REIFSNYDER:

* * *

[2164]

Q. At page 5, line 16, of your testimony, which is transcript 581, you state the future exploration and production costs should average out to the costs underlying the Commission's area rate determination. Do you mean by this they should average out for each pipeline over the years or average out for the group? A. They should average out for the group.

Q. Will they average out for the pipelines in your judgment, sir, for each pipeline? A. They may or they may not, depending on the luck they have.

Q. Mr. Deutsch, based on Mr. Murr's Exhibit 60-J, which is now Item I, by reference, in this proceeding, the sheet I handed your counsel this morning indicates there has been substantial variation in production costs among the pipelines. Do you agree with that? A. What is the title of that sheet?

Q. It is entitled "Comparison of individual pipelines' unit production costs for owned gas production per Staff Witnesses' R. D. Murr Exhibit, Item I, by reference, Continental United States 1962.

* * *

[2172]

BY MR. REIFSNYDER:

Q. Looking at page 5 of your direct testimony, sir, line 23, transcript page 581. You assert that a continuation of cost of service policy in the future would provide producing pipelines with an unnecessary special incentive to explore and develop. Is it your position that the Commission in the past and at the present time in its cost of service regulation of pipelines has allowed an excess rate of return?

MR. DIETRICH: When you say rate of return, Mr. Reifsnyder, are you using that term synonymously with his word incentive?

MR. REIFSNYDER: I have to take his language. He speaks at the bottom of page 581 with an unnecessary special incentive

[2173]

in referring to the result of the Commission's cost of service column. That suggests he is or isn't saying they are getting too much, and I want to know what he means.

MR. DIETRICH: I wanted to know how you used the term "return". I understand you use it synonymously with incentive.

MR. REIFSNYDER: I am trying to understand his usage of these words.

BY MR. REIFSNYDER:

Q. What do you mean when you say continuation in the future of the Commission's cost of service policy for individual company's gas production would provide them with an unnecessary special incentive? Are they getting an unnecessary special incentive now? A. They are in a protective posture because they are assured of all their production costs plus a return.

Q. Does not that return take that into consideration? Isn't that the purpose of applying a special rate of return to each company? A. The purpose of a return is to provide just enough incentive, no more than is necessary.

Q. Are you saying they have been provided with too much? A. Yes, under cost of service I would say they are provided with—they are in a protective posture and they have this additional—it is an unnecessary incentive, yes.

PRESIDING EXAMINER: Mr. Deutsch, is it because an

[2174]

inefficient producer also gets all his costs and also the return on investment?

THE WITNESS: That is correct.

PRESIDING EXAMINER: That is what protects him?

THE WITNESS: Yes, sir. He gets all his costs no matter what they are, whether he is an inefficient or an efficient producer.

* * *

[2192]

BY MR. REIFSNYDER:

Q. Under the area rate method that you recommend, where would we recover our costs for bringing this gas up to pipeline quality? A. In your cost of service.

Q. What part of the cost of service, sir? A. The pipeline companies recover their costs for treating their gas.

Q. I understand that we do under the present situation. A. I am not recommending that the cost of service be abandoned for functions beyond the wellmouth.

Q. Let me direct your attention to page 40 of the mimeographed copy of Opinion 468. I notice an entry marked "Net Liquid Credit". What do you understand that to be, sir? A. That is the revenues received for liquids extracted at the well and also for plant liquids.

Q. So there is a plant liquid figure in this, isn't there? A. Yes.

Q. And it does go beyond the well contrary to what you

[2193]

just said, does it not? A. To a certain extent, yes.

Q. Does that cause you to want to make any adjustment in your figures, sir? A. No, I wouldn't want to make any adjustments. This would be something that we would consider under an individual company case.

Q. In other words, we now have three adjustments: Taxes, rate of return, and net liquid credit under your theory; is that right? A. No. Well, rate of return, that is one adjustment. Taxes, there is no adjustment, that is zero taxes. As to whether there will be any additional adjustment we would have to take it up under an individual company case.

Q. How do you know there will be zero taxes, sir?

MR. LEITHEAD: Did the witness indicate there would be zero taxes?

MR. REIFSNYDER: Yes.

MR. LEITHEAD: I am sorry, I missed that.

THE WITNESS: Generally, a Company with an active producing production department will have zero taxes.

BY MR. REIFSNYDER:

Q. Have you made a study of this company by company? A. No, I haven't made a study of it, but I am aware of this situation in several cases that I am familiar with before

[2194]

the Commission.

Q. Has any Staff witness in this proceeding made such a study? A. I can't answer that. I don't know.

Q. You will agree that no Staff witness has presented such a study here, would you not? You are not aware at this time of any such study that has been made, are you?

MR. DIETRICH: You are distinguishing studies as apart from testimony that we presently have in the record?

MR. REIFSNYDER: Yes.

THE WITNESS: I am not aware of any.

* * *

[2206]

BY MR. REIFSNYDER:

Q. We have been speaking of the manner in which you used the term "inefficient," have we not, and I simply as my final question on this point wanted to make sure that you don't necessarily feel that a producer who has high costs is inefficient. For example, my 5,000-25,000 a day analogy. A. Again, if the average cost of a producer is much higher than the average cost of a large group of producers, I would say he is an inefficient producer, too.

Q. Would you look at transcript 584 with me, please, folio page 8 of your testimony. I am directing your attention to line 3. You state at that point that "pipeline production costs have been above the costs of other production when compared on the basis of some common denominators or common allocation method."

What common denominators do you refer to, sir, or do you have in mind? A. Well, the common denominator would be cents per Mcf.

Q. Are there any others? A. Another common denominator may be comparing one ratio

[2207]

to another ratio.

Q. Do you have an example in mind, sir? A. Yes. I would refer you to Mr. Bass' Exhibit 5.

Q. Do you have a schedule in mind, sir? A. Yes, Schedule No. 2.

Q. Before I get to Mr. Bass, did you have any other common denominators there, sir? A. Comparison of R/P ratios.

Q. Comparison of R/P ratios? A. That is right.

* * *

[2227]

Q. In your judgment, was pipeline data included in that source, sir? A. I can't answer that unless I look at Exhibit 224.

Q. Perhaps your counsel will stipulate with me it was based on Appendix B.

MR. DIETRICH: I will stipulate that it is based on the Exhibit 142 in those proceedings.

MR. REIFSNYDER: All right, sir.

Would you stipulate that 142 doesn't have pipeline data in it, Mr. Dietrich?

MR. DIETRICH: I think that was covered by my stipulation.

MR. REIFSNYDER: I just wanted it to be clear.

* * *

[2240]

Q. Would you look at transcript 584, line 21, folio 8 of your testimony. You refer at that point to what you describe as situations where lease sales are made at high costs to pipelines to circumvent effective producer rate regulation. Have there been many of those, sir? A. I can think of approximately three of them.

Q. Would you agree with me that there is little chance of that occurring in the future under the Commission's present policies? A. Do you mean by the present policy conditioning?

Q. Yes, sir, and any other actions that we know they have been taking. A. Yes, that would be true, but I feel my recommendation would do the same thing, only in an easier way.

* * *

[2252]

Q. At transcript 591, line 21, you refer to certain data groupings. Would you describe for me the groupings to which you refer and tell us who prepared them? A. The groups I refer to are Groups I, II, III, and IV. They were prepared in informal conferences, and for my presentation I have reviewed the groupings, I think they are logical and I have accepted responsibility for these groupings.

Q. Are you talking about informal conferences among the Staff? A. Among the Staff, yes.

Q. Mr. Deutsch, can a composite cost of service be computed from the PPQ?

[2253]

A. No, it can not.

Q. Can an individual company cost of service array be computed from the PPQ? A. No.

Q. Would you tell me, sir, why the Staff did not request production cost and expense data for the PPQ similar to such data requested on Schedule G of the AAQ? A. I did not participate in the request for data, so I can't answer.

Q. Who made that determination, sir? Do you know? A. I think it was again a group effort. Various people participated. I understand there were conferences where they discussed the type of data to be supplied. There was agreements made whether certain data would be supplied or not. That is about all I can say about it.

Q. And you were not a member of that group, though? A. No, I was not.

Q. Mr. Deutsch, if the production cost and expense data had been requested, would it have been possible to compute a composite cost of service?

MR. DIETRICH: Objection, speculative. If we had requested the same data in the same format as the AAQ, I would certainly stipulate. I am not sure what the relevance of this line is. We had the AAQ data available for 1962. Much of the PPQ data was requested in addition to that in the AAQ. If El Paso is

[2254]

thinking about collecting production cost and E&D expense data for some year beyond 1962, I would think they could address their request and questionnaire to the Commission and we could discuss it.

MR. REIFSNYDER: Mr. Dietrich has satisfied me with his statement.

* * *

[2273]

You state the pipelines appear to be able to readily purchase their necessary flexibility from independent producers. If a pipeline were not able to purchase necessary flexibility without acquiring its own leases and engaging in its own drilling, would you still deny it its costs if they exceeded the industry average? A. I don't know of any pipeline that hasn't been able to purchase its flexibility from an independent producer.

Q. This is Phase I and we are talking about the future. A. Does your question imply that if there is no other way of getting gas, then you have to go out and find it?

Q. If it is unable to purchase the necessary flexibility from independent producers, my question is would you still deny it its cost if they exceeded the industry average?

[2274]

A. That may be an exception.

* * *

[2331]

BY MR. BROWN:

* * *

Q. So that you would expect pipelines to have higher DD&A costs in all areas of the country, and I mean higher than the independents on the average? A. You say in all areas, do you mean—

Q. On the average. A. On the average, yes.

Q. Would you expect that to be true in the future? A. When you say do I expect it to be true in the future, do you mean under cost of service pricing? If it is, I would.

[2332]

Q. I mean the actual costs that they incur. It has nothing to do with cost of service. I just wanted to know if you think they will incur higher D. D. & A. cost in the future. A. The Staff has analyzed certain cost data comparing pipeline production companies with independent producers, and these cost data reflect that the pipeline producers are higher producers, and I would expect that to continue.

Q. Higher cost producers? A. Higher cost producers.

Q. At transcript page 582 you testify that "The effect of my modified area rate Phase I recommendation would be to impute national average finding and production costs to pipelines instead of their actual costs". Is that correct; A. That is correct; instead of their actual—that is right.

Q. By "national average finding and production costs" you mean the national average for pipelines, affiliates and independents; is that correct? A. No, I mean the cost as determined by the Commission in Opinion 468. I am using that as my standard cost.

Q. That is an average for all producers, isn't it, not just pipelines? A. It is based on an average industrywide cost; that is correct.

[2334]

A. I would not expect that; that is, when I say I would not expct that to hold in the future, I mean under my recommendations.

Q. What is the basis for that statement, Mr. Deutsch? A. The basis for that statement is that I would expect the pipelines to become more efficient in their production operations.

Q. How would they go about doing that? How would they change their operations?

MR. SHIBLEY: By accepting his recommendation.

PRESIDING EXAMINER: Let the witness answer the question.

THE WITNESS: For one, they may not acquire high-priced properties.

BY MR. BROWN:

Q. When you are speaking of these high priced properties, do you have reference to in-place purchases? A. Yes, and also in acquiring developed properties, more developed properties. I have reference to both.

Q. How many in-place purchases do you know about that pipelines have made?

[2335]

A. I know I think of three.

Q. It really hasn't been a widespread practice in the past, has it? A. I don't know whether it has been widespread or not, but I can't see why the consumer would have to pay higher cost for that reason when the pipelines can purchase the gas cheaper.

Q. Only two pipelines were involved in those three purchases, weren't there? A. I don't recollect that it was two or more.

Q. It was Tennessee and Texas Eastern. The three fields are Bastian Bay, Ship Shoals, and Rayne.

MR. DIETRICH: How about El Paso?

MR. BROWN: Perhaps Mr. Reifsnyder can enlighten me on the El Paso situation.

MR. DIETRICH: Do you have a comment?

MR. REIFSNYDER: I have no comment. The witness has shown a sigular lack of familiarity with the San Juan Basin.

BY MR. BROWN:

Q. How many of those in-place purchases took place in the Hugoton-Anadarko and Texas Gulf Coast area? A. Do you want me to tell you where each one took place; is that what you want?

Q. No, I just want you to tell me how many of those in-place purchases took place in the Hugoton-Anadarko and Texas Gulf Coast area where you have testified in the past the unit

[2336]

D. D. & A. is higher on the average for pipelines than it is for independent producers.

MR. REIFSNYDER: Could I have the question read back? I don't understand it.

MR. BROWN: I withdraw the question, Your Honor. I think I am confused.

BY MR. BROWN:

Q. How many of those purchases took place in 1962, in-place sales, took place in 1962? A. I don't have the exact date that these sales took place, Mr. Brown. If you have it, I will accept it.

Q. Would you accept subject to check that none of those in-place sales took place during the year 1962? A. I will accept it–

MR. DIETRICH: What date is he supposed to check as to which years they did occur? Do you have the information? You want him to research this for you?

MR. BROWN: No. It is my recollection, and I am not absolutely positive, that Ship Shoals took place in the year 1960 and Bastian Bay was 1961, and I believe Rayne field was before that.

[2336]

MR. DIETRICH: When Mr. Brown obtains this information we will be glad to accept it subject to check, but there apparently is some lingering doubt in his mind as to what the precise dates are.

[2337]

MR. BROWN: It is reported in the official Federal Power Commission reports. I will check it over the recess and provide the information for the record.

BY MR. BROWN:

Q. I believe you also told me in addition to the in-place purchases that pipelines were purchasing more highly developed properties; is that right? That is why they have higher costs? Those were the two reasons you gave me for the D. D. & A. costs. A. It would appear that way from our analysis.

Q. Let me see, when a pipeline buys partially developed properties it reduces its E. and D. costs, doesn't it?

MR. DIETRICH: What is the basis for that assumption, Mr. Brown?

MR. BROWN: If the gas is there you don't have to go and look for it.

MR. DIETRICH: I am not sure that follows. The basis for my reason is in AR64-1 and AR64-2 Witness Fisher calculated an E. and D. cost for pipelines of 4.5 cents, and a comparable cost for the independent producers was less. So I am not sure that Mr. Brown's assumption necessarily follows. I think I am right on that.

MR. REIFSNYDER: 64-I?

MR. DIETRICH: AR64-1 and AR64-2.

* * *

[2365]

BY MR. SKINNER:

Q. I do want to make sure, though, that the record is clear that you envision that your modified area rate proposal would provide some exemption procedure. A. Yes.

* * *

[2448]

Q. I think you agreed, didn't you, Mr. Deutsch, that pipeline producers are not producing in all areas; in other words, the distribution of pipeline production in the areas which they are producing may be different than what is the case on the basis of a national average? A. I don't know what your question implies, but the pipeline producers are producing all over the country.

Q. But wouldn't you agree that the concentration of their production may be different substantially than the average in terms of the locale of the production? A. That may be true, but the industrywide average cost includes all producers. It includes pipeline production, it includes independent producers, and we have a very large cost sample, so we can use that as a standard.

Q. You are comparing one segment of the sample to this large group; isn't that right? A. Well, it is an industry wide average cost over the U. S. Yes–

Q. You are comparing that industrywide segment, one segment of the group, to that large group; isn't that right? A. That is correct.

Q. And the characteristics of the production of this segment may be different than the large group; isn't that right? A. That is correct.

Q. And the characteristics of the production of this

[2449]

segment may be different than the large group; isn't that right, in terms of the locale of production? A. I don't see why in the future it should be any different.

* * *

[2484]

Q. If a higher than average cost pipeline producer determined that in order to meet the company's objectives for gas supply it should nevertheless engage in exploration and production activities, what resource would it have with respect to recovering its legitimate cost in its rates?

[2484]

MR. DIETRICH: May that be read?

MR. NORRIS: Mr. Examiner, I object to the question on the basis that the witness yesterday stated in individual cases he would make an exception in this modified area rate. I submit what Mr. Wheatley is now raising may be one of those individual exceptions. It is not to be treated in the context of this proceeding which is to establish rates for the pipeline industry as a whole as I was forcibly advised yesterday.

MR. DIETRICH: Mr. Norris anticipated my objection. I think this matter came up in the cross-examination of Mr. Skinner, where the witness indicated he would go along with the procedure of 468 whereby somebody under special circumstances could petition for exemption.

PRESIDING EXAMINER: This is the very answer that you are seeking; is that right?

MR. WHEATLEY: Yes.

PRESIDING EXAMINER: You have it now.

BY MR. WHEATLEY:

[2485]

Q. Do you agree there would be special exemptions as described by counsel? A. That is what I testified to the other day.

[2486]

Q. I presume these are what you suggest in your testimony at transcript 593, folio 17, line 1, where you say, "However, I would expect individual companies to advise the record of material instances where their needs and special differences should be noted," and also at page 625, folio 49, beginning at line 25, where you state, "If I believed that there was a specific justification for any particular additional costs incurred by pipelines, which resulted from necessary differences between their operations and those of independent producers and which resulted in a commensurate advantage to the consumer, I would recommend possibly

subsidizing the incurrence of such costs." Are these examples of these exceptions that you refer to? A. Yes, I would assume that an individual pipeline company would come in and would quantify the advantages accruing to the consumer and demonstrate first that there are advantages and then quantify them, but that is what I had in mind.

Q. You stated earlier to one of my questions that it would be very difficult to determine on an individual pipeline basis whether or not an individual pipeline company was in fact making an imprudent investment when it incurred high costs of production.

It is true in the past, is it not, that the Commission has followed under cost of service principles a requirement that any cost be prudently incurred, reasonably and prudently incurred; that is a part of established Commission policy, is it not?

[2487]

MR. DIETRICH: That is probably a triply compound question. I don't know whether it is a statement of counsel or a question.

BY MR. WHEATLEY:

Q. Do you have difficulty understanding my question? A. Could I have the question read?

(Question read.)

THE WITNESS: That is correct.

BY MR. WHEATLEY:

Q. Is it fair to presume also that the existing high-cost producers—the costs that they have incurred since they are unregulated by the Commission under cost of service principle are prudent and reasonable; isn't that a fair presumption?

MR. NORRIS: Objection, Your Honor. This gets back again to Phase II of the hearing. I don't know that we would want to characterize existing production as imprudent or in any other manner. I think this should be reserved for Phase II.

[2487]

PRESIDING EXAMINER: Let the witness answer the question, but Mr. Norris is probably correct in asserting that it isn't going to help us much.

Can you answer the last question? Do you want it read?

THE WITNESS: I think I understand it.

I would say, Mr. Wheatley, in retrospect perhaps some of those costs were not prudent costs.

MR. TALISMAN: By "retrospect" you mean 20-20 hindsight?

[2488]

THE WITNESS: That is right.

MR. DIETRICH: Now that we know what the area rates are.

BY MR. WHEATLEY:

Q. Mr. Deutsch, you did state that you would make exceptions for the case where it appeared that high-cost production was prudent. A. Yes, but the individual pipeline company would have to demonstrate that there are benefits —substantial benefits and quantity those substantial benefits to the consumer.

Q. If you make an exception, though, then, in effect you have a system of area rates or cost of service, whichever is higher?

MR. BROWN: Objection, Your Honor.

PRESIDING EXAMINER: The objection is sustained. We basically covered it yesterday.

* * *

[2509]

Q. Would you expect the area rate scheme which you are recommending for pipeline producers to increase their drilling activities and increase their tax loss spillover generated by their exploration and production activities? A. Yes, I would.

Q. In the course of your regulatory experience, have you detected any tendency on the part of natural gas pipeline

companies to attempt to retain for their own benefit instead of passing on to consumers any tax deductions attributable to such items as percentage depletion, drilling costs, liberalized depreciation, and the like? A. Yes, they have.

Q. Do you understand that the income tax law allows these special deductions to be offset against any kind of income the taxpaying entity may have?

MR. SHIBLEY: I object, Your Honor.

MR. BROWN: I object.

[2510]

PRESIDING EXAMINER: The objection is sustained. It should have been asked of Mr. Raymond, and I suppose if you want to form it in the form of an interrogatory maybe Staff Counsel will give you the courtesy of a reply.

MR. DIETRICH: We will consider it, but it is going to be a belated interrogatory. I really feel I cannot hold Staff personnel available indefinitely on these matters. I am sure Mr. Smith is familiar with the tax laws. He knows of Mr. Wheatley's problem on the score, and he is here, and he can handle it.

MR. WHEATLEY: We are simply seeking to explore what Mr. Deutsch considered in this matter.

MR. DIETRICH: He should have found out what Mr. Raymond considered in this matter. He had that opportunity.

PRESIDING EXAMINER: If there is a gap Mr. Smith will enlighten us about it; is that right, Mr. Wheatley?

MR. WHEATLEY: We think the enlightenment, Your Honor, if this is a gap in the Staff case, might affect their reasoning and their conclusions, and that is the reason for these questions.

MR. DIETRICH: We appreciate his concern, Your Honor. We will look after the Staff case. I am sure it will be complete when the record is closed.

* * *

[2783]

[Witness Jones]

Q. As a simple wrap-up on Mr. Quinn's Exhibit 82-1, I will ask you if the result shown by Mr. Quinn utilizing a 12.5 percent royalty, a production tax of 7 percent, and a plant liquid credit stipulated from Permian of 0.2 cents, is shown on

[2784]

page 1 of Exhibit 82-1 as being 18.43 cents?

MR. SHIBLEY: For all producers?

MR. ARNETT: Yes, sir; for the industry.

THE WITNESS: That is correct.

BY MR. ARNETT:

Q. And Mr. Quinn's data did include pipeline data; is that true? A. That is correct, as has all data in the cost of new gas studies presented in all area rate hearings.

* * *

[CROSS EXAMINATION]

* * *

[BY MR. WHEATLEY:]

* * *

[3036]

[Witness Dunn]

All of this, of course, occurred prior to the time that Union was subject to regulation. They were, of course, referring merely to the fact of ownership of stock. In no way did they refer to the nature of Union's operations, which is the same as an independent producer. It has large oil operations which, of course, in no way have anything to do with pipeline operations. It has always been treated by the Commission as an independent producer in rate cases. Union's costs have never

[3037]

been included in a pipeline cost of service. The Commission had an expensive hearing to determine whether or not

Union should be an independent producer and declared that it should be, which I have referred to in my direct testimony. Since that court decision that the Commission referred to, we have had the same court discussing that very decision, which I find of considerable interest because it really makes it clear that Union is an independent producer and that affiliation has nothing whatever to do with the reasonableness or justness of the Union-United rates, and that appears in the America Louisiana Pipeline Company, et al., versus The Federal Power Commission, United States Court of Appeals, District of Columbia, and I particularly refer to page 532 reported at 344 Fed. (2d), the footnote 12 says:

* * *

[3057]

W. M. ELMER

was called as a witness, and, having been first duly sworn was examined and testified as follows:

MR. SHIBLEY: Mr. Examiner, we have been requested to thank the parties for accommodating us with regard to the scheduling of Mr. Elmer for today.

DIRECT EXAMINATION

BY MR. SHIBLEY:

Q. Mr. Elmer, your prepared testimony has been copied into the transcript, Volume No. 8, part 1, commencing at page 706 and extending to 721-A. Have you had occasion to review that prepared testimony? A. Yes, sir.

Q. Does that constitute your testimony in this particular portion of the proceeding? A. It does.

MR. SHIBLEY: We tender Mr. Elmer for cross-examination. He has no exhibits.

[3058]

CROSS-EXAMINATION

BY MR. REIFSNYDER:

Q. Mr. Elmer, as I am sure you know, my name is Reifsnyder. I represent Natural Gas Company in these proceedings.

At transcript 708, Mr. Elmer, you state your presentation is being made for the so-called Pipeline Production Group which you state consists of some 13 natural gas companies. Would you identify those companies for the record, sir, please? A. It is now actually 14. There was one that came in after I prepared that testimony. They are as follows:

Colorado Interstate Gas Company
Kansas-Nebraska Natural Gas Company.
Lone Star Gas Company.
Natural Gas Pipeline Company.
Northern Natural Gas Company.
Panhandle Eastern Pipeline Company.
Southern Natural Gas Company.
Texas Gas Transmission Corporation.
Transcontinental Gas Pipeline Corporation.
Trunkline Gas Company.
United Fuel Gas Company.
United Gas Pipeline Company.
Cities Service Gas Company.

And the fourteenth one that was not in at that time, Humble

[3059]

Gas Transmission Corporation.

MR. REIFSNYDER: Mr. Examiner, may I say for the record that I have tendered a list of interrogatories asking for some specific factual information to Mr. Elmer, and Mr. Boland has graciously consented to furnish the information. I understand it will be made available for the record as soon as it is convenient, as soon as they are able

to put it together. I want to express my appreciation to them. I think it will shorten the cross-examination.

[3060]

BY MR. REIFSNYDER:

Q. Mr. Elmer, near the middle of page 710 of the transcript you make reference to joint operations between pipelines and independent producers. Have you made a study indicating the degree of such interest operations? A. Not a study as such. I have been involved in pipeline production principally as the result of our subsidiary since 1952 and have been active in reviewing those of their deals, their projects, the ventures that they have gone through, their drilling operations, and I have seen as each year goes by, and I am speaking principally of Gulf Coast operations where we have the bulk of our operations, the costs are getting so great that there are very few ventures that are made involving a pipeline production company, whether it be a division or others, where there are not joint operations with one or more independent producers. There are very few any more that we see that are straight up hundred percent deals. This is just from my day to day knowledge. But I don't know of any major drilling ventures for gas or oil that we have gone in, or that I see the other pipeline producing companies go in, that don't have involved in the deal one or more independent producers as a partner.

Q. And this general knowledge of yours is the basis for your statement that a trend of this type of arrangement is increasing? A. Yes, sir, and that trend, as I stated, I believe is

[3061]

because it is becoming more costly each year and also that the leasing has gone on and on, so it is almost impossible to pick up any major lease, so you have to have a joint deal to have any sizable lease to put together.

[3061]

Q. Also at transcript 710 you state there are not basic differences in exploration, development or production. Do you mean there are not basic cost differences; is that what you principally had reference to? A. I don't think there are any basic differences. You have to go through the steps that one has to go through, first geological, geophysical, the leasing, the physical steps. Certainly you go through the same steps regardless of what your name is or who owns you. The costs are exactly the same. It doesn't make any difference who owns the company. The cost is the same for drilling a well or doing a geophysical, geological or leasing work.

Q. At transcript 711, Mr. Elmer, you state a few pipeline companies have withdrawn from the producing business. Could you give us some examples of that, sir? A. The two that come to my mind are Northern Natural Gas Company and Cities Service Gas Company.

Q. You also state at this point that there are other pipelines who have made no effort to go into the producing business. Do you have any examples in mind? A. Principally Transcontinental and Florida Gas Corporation

[3062]

Q. At transcript 712, sir–

MR. SHIBLEY: Mr. Elmer, you were referring to Florida Gas Transmission?

THE WITNESS: Yes, Florida Gas Transmission.

MR. SHIBLEY: The pipeline company?

THE WITNESS: The pipeline.

BY MR. REIFSNYDER:

Q. Winter Park, Florida? A. Winter Park, Florida.

Q. At transcript 712, sir, you state that the business of searching for and producing gas and oil is undeniably a very difficult, competitive and risky one. By this statement do you mean to imply that the members of the group for whom you appear contemplate engaging in oil drilling programs as well as gas drilling programs if you are successful

in securing area rates for Phase I? A. Yes, sir, because we don't know when we drill exactly what we are going to get. There are areas where you have a much higher percentage of finding gas than you do of finding oil and vice versa. So many times it is possible to find gas when you think you might find oil or vice versa. We are in business, I will speak for our own subsidiary, we run our subsidiary the same as an independent producing company seeking to find both gas and oil, and even in an area where the chances are the best of finding oil, if we get a good lease, we will

[3063]

drill in that area. So we look for oil as well as looking for gas.

Q. At transcript 715, Mr. Elmer, you state you do not believe there is any danger to the financial integrity of the pipeline companies through participation in high risk production operations. Is the risk higher for production operations than in the transmission operations in your opinion? A. Oh, completely; much, much greater.

Q. May I ask you this question. Would the return requirement for the production operations be higher? A. Of course. They are two completely different types of operation.

Q. At transcript 617 you state that a majority of institutional investors believe that a well-managed production department is an asset to the financial standing of the pipeline company. Is it your judgment that such a well-managed production department results in an in fact lower cost of capital? A. A lower cost of equity capital?

Q. Yes, sir. A. Yes, sir, it does result in a lower cost of equity capital.

Q. What is your judgment about on an overall basis, sir? A. The production operation of a gas pipeline company, whether it be through a subsidiary or through a division, is in

[3064]

almost every instance a minor part or a small factor compared to the dollar volume of net and gross investment in the pipeline operation; so, when a senior debt issue is sold by a pipeline company, I don't believe that the extent of their production activities enters into it too much as such. The principal factor today in determining the cost of senior debt to a pipeline company is basically, one, that it is in the pipeline industry and it is so classified by the investor as he classifies the entire industry as a class of investment; and, second, the coverage that that company has. I am talking about the issue by the pipeline company as such.

To the extent that the overall coverage is improved by the company being able to make a greater return on its investment in the production operation than it does in the pipeline company, that helps the coverage and that in turn would help your rating and that in turn would help your price. But the fact that you are in the producing business as such, the romantic aspect of it, you might say, to the investor, that factor does not, in my opinion, enter into the cost of senior debt. It does enter into the cost of the equity capital. I believe a company with a successful production operation or extensive reserves of their own gets a higher equity capital, but other than the effect that the earnings that the subsidiary may have or the division may have to increment the earnings that they would otherwise make on a straight pipeline operation and in turn its

[3065]

effect on coverage, that would be the only effect it would have on the senior debt.

Q. Mr. Elmer, at transcript 717, you refer to the similarities and comparability among the various categories of producers. So I will not overlook any similarities you have in mind, would you tell me, please, whether those you list at transcript page 710 are all of the similarities among the various categories to which you refer?

MR. SHIBLEY: Are you now referring to 710 or 717?

MR. REIFSNYDER: I am referring to 710 as the list of reasons, but at 717 he refers to similarities and comparability. As I read his testimony, Mr. Examiner, at page 710, he gives an outline of these things. I am simply asking if there are any that he had reference to at page 717 that he failed to list on page 710.

THE WITNESS: I think if you go back to page 710, the first sentence of my answer on page 710 where I say, "I would inlcude all significant characteristics, such as technology, methodology, cost incurrence, availability of funds, and capabilities." I think that covers the waterfront.

BY MR. REIFSNYDER:

Q. At transcript 721, you state, "If individual cost-plus arrangements are not sound for the independent producers, they are equally unsound for pipeline producers."

Do you base this statement on what you believe to be

[3066]

similarities between pipelines and independent producers? A. That is right. I think the operation is the same. You have the same similarity between two companies, one that is owned by an independent producer and one that is owned by a pipeline, as you do between two companies owned by independent producers that have two different names. My whole testimony is in effect based on this. I don't think there is any difference from my experience.

Q. Did the so-called administrative convenience play any part in the Commission's determination that individual cost-plus arrangements were, as you put it, not sound for independent producers? A. You will have to explain that to me, what you mean, the administrative convenience.

Q. We have been referring in this proceeding, sir, to language in some of the court and Commission decisions which refers to administrative convenience on the part of the Federal Power Commission in dealing with regulation of producers and group and area pricing concepts as opposed to the

[3066]

cost of service concept. I was simply asking whether in your judgment administrative convenience played any part in the change and regulation of independent producers, that is, change in the sense that they are regulated on an area basis whereas pipelines have been traditionally regulated on a cost of service basis.

MR. SHIBLEY: Just to preserve our position, I am not sure

[3067]

that Mr. Elmer ought to be called upon to explain what the Commission's motivation was other than the way they have explained it, but if Mr. Reifsnyder is doing no more than asking Mr. Elmer to agree that the Commission has mentioned administrative convenience, I would think it was unobjectionable but also largely innocuous.

THE WITNESS: I would say this: Keep in mind, Mr. Reifsnyder, we are talking about only one thing in this proceeding, and that is the future production. That is Phase I. Is this Phase I?

MR. SHIBLEY: Yes, sir.

THE WITNESS: I get confused which is I and II.

Call it administrative convenience, call it anything you want to, I just don't think it is workable or practical to try to regulate either the independent producer or any producer to regulate its gas production, part of its gas production I might say, on a cost of service basis.

I would like to add to that, as I stated earlier, my principal experience in this area is in the Gulf Coast region. And from what has been explained to me by some of the people that I am testifying for here, I mean speaking specifically to you, I am not familiar with the San Juan area. That is the one area that I am not familiar with.

[3068]

BY MR. REIFSNYDER:

Q. So I might be clear about the statement at transcript 721-A, Mr. Elmer, you refer there to additional incentives to do a more economical job which pipelines would have. So that I may be entirely clear, you are not suggesting that pipelines as a group have been imprudent in production operations in the past, are you, sir? A. No, I am not, and I am talking about the future. You know, you can always get more out of an employee or an officer if you let them know that they are going to make money for their company. I think if they see, through real hard looks and some luck, and it takes some luck in this, if they are able to come up with some gas they would make a little more money than they would on something else they would do, it is just a good incentive for them.

Q. You are familiar with Mr. Dickinson's testimony at transcript 651 that it would take a pipeline from six to eight years to achieve a successful exploratory operation, are you, sir? A. I am not familiar with that, but I certainly agree with it.

Q. That was going to be my question, whether you did agree with it. A. Yes, sir.

Q. Mr. Elmer, do I understand you to believe that unless

[3069]

pipelines are given area rate treatment for the future produced gas that they will cease exploratory activity? A. No, I don't think we can make that statement categorically. I think to the extent that they are not given similar treatment as the independent producers, and to the extent that that gap widens in the same proportion will decrease their enthusiasm for the operation. Now, at a point, I am sure a point could be reached where your statement would be true. We are in the business of selling gas and of serving the public, and to do everything we can to obtain gas.

[3069]

But the incentive and the responsibility that we have not only to our consumers but to our stockholders is a point that you have to look at carefully, and I am saying you will get the most enthusiasm, and more than you are getting now, in my opinion, and more interest and more activity than we are getting now, if a policy is set where they know they will get the same treatment as the independent producer.

Moving down from there is just a matter of degree and enthusiasm.

* * *

[3072]

Q. Mr. Elmer, you have testified before the Federal Power Commission before, haven't you? A. Yes, sir.

Q. In which proceedings have you testified? A. Oh, I can't remember, sir. I testified before the Commission for over a period of 20 years. I can't recall right now.

Q. Were the proceedings all involving Texas Gas Transmission Corporation? A. I believe that is right; yes, sir.

Q. Most of them would have been certificate proceedings? A. And rate proceedings.

Q. Do you recall the most recent one in which you testified? A. My counsel may.

I think our last rate proceeding, which would be about 1963.

MR. BOLAND: I think it was Docket G-2345. It was an original cost matter.

THE WITNESS: I can get you that information if you want it, sir.

MR. DIETRICH: I would like to have it, yes.

MR. SHIBLEY: We shall supply it.

BY MR. DIETRICH:

Q. Mr. Elmer, I understand it is your recommendation that the area rate be accorded future production by pipelines, and

[3073]

that the area rate would not be modified in any way? Is that correct. A. I have to qualify that. Our recommendation is that for future production, or the production covered by Phase I, the pipeline owned through division or affiliate production be accorded the comparable treatment of that of the independent producer. You are assuming, and it is a good assumption, that it is going to be area rates. If the independent producer is regulated by area rates, then the answer to your question is "yes."

Q. The area rate determined to be appropriate by the Commission in the Permian Basin proceeding included a 12 percent rate of return? A. If you say so; yes, sir.

Q. And a portion of that return was attributable to a risk factor known as the risk of finding gas that wasn't pipeline quality; is that correct? A. I am not familiar with that.

MR. SHIBLEY: Mr. Examiner, I think Mr. Dietrich will agree with me that there was a considerable question about whether that particular finding was retroactive or really part of that process, and I think that matter is pending in another tribunal down here. I really don't know whether we ought to interfere with the fight that is going on between the Staff and the producers on that issue. As Mr. Elmer has said, whatever it is, if

[3074]

it is good enough to keep the producers alive, we ought to have a crack at it in that vein.

MR. DIETRICH: It isn't necessary for the purpose of my questioning that he understand in detail whether or not it was known as a risk of finding gas of less than pipeline quality, and he doesn't have to attempt to substitute his own opinions for those of the Supreme Court.

What I am getting to is whether or not he would be recommending deductive charges be applied against pipeline produced gas which is sub quality.

[3074]

THE WITNESS: Let me try to answer it this way, sir. Regardless of how you arrive at the area price for the independent producer and regardless of what treatment you give sub quality gas, and how you go about it, our recommendation is that we have the exact treatment. In other words, if in a specific area proceeding you fix a minimum Btu to which the area price applies and below that gas sold below that Btu would have to have a deduction as specified, whatever that is for the independent producer, I say that should be also true for the pipeline.

Does that answer your question?

BY MR. DIETRICH:

Q. The answer to my question is "yes," as I understand your answer? A. Yes.

[3075]

Q. Is that right? A. Yes.

Q. Now, the producers, as you probably know, are required to file quality statements indicating the quality of their gas. Is that your understanding? A. I guess so. I don't know it. You know this, and whether that is true, it is great, yes.

Q. And those quality statements are the product of discussions with the piepline producer and the customers, and they agree with what is the quality of the gas and the charges to be determined? A. It is a simple matter to determine the quality, yes.

Q. Would the pipeline producers do the same thing? A. I think they should; yes, sir.

Q. Their production department would get together with various members who know this information and they would file a quality statement? A. Although they are the same, I think you have to answer each of these questions one on the basis of the subsidiary, one on the basis of the department.

On the basis of the subsidiary, or the affiliate, there would be no problem. It would be the same as the independent producer. Where it is a separate department, I see no reason why

it shouldn't be the same as buying from an independent producer. It is not a matter of negotiation of the parties. It

[3076]

is a matter of chemical analysis.

Q. The rate for gas sold from an independent producer to a pipeline company is established by a gas purchase contract; is that right? A. Yes.

Q. And these gas purchase contracts indicate perhaps varying rates depending on which field is producing the gas that is being bought in a given area such as the Southern Louisiana area? A. Usually one contract has one price.

Q. That is right. A. Yes, sir.

Q. And they vary somewhat among the various fields? A. Yes, sir.

Q. What comparable document would the pipeline producers furnish indicating the rate that they are charging with respect to a given field? A. Again, the subsidiary would be the same, they would file such as they do now.

As to the department, I think that is something that would have to be worked out, maybe specified in a Commission order, that the producing department or that the company itself should furnish to the Federal Power Commission for the record and for others to see, call it a statement or something like that a contract that would incorporate the same basic data the contract

[3077]

would incorporate so the Federal Power Commission could have that data, so that any interested party could have that data. This isn't the procedure now, but I have thought about this problem myself, how would it work. I think it is a matter of mechanics. But I think it would be advisable to have some standard procedure that everyone followed from your standpoint.

Q. It would be your recommendation, then, that the pipeline producer would determine that he had gas produc-

[3077]

tion in a given field where there were also other independent producers perhaps and he would incorporate the provisions of their gas sales contracts into some pipeline document reflecting more or less the same provisions of sale. A. I am not saying that. I am saying if a pipeline division is going to supply gas–first, we have got to assume some policy is set as a result of this hearing. If there is a fixed treatment, and let's assume for the moment it is our recommendation, just for the purpose of answering the question, and that it is the area price, then a division it would seem to me of a company, not a subsidiary, because a subsidiary is automatic, but a division when they enter into an arrangement among themselves, or decide to hook up gas to their system would prepare some kind of a statement–I think it should be a standard form; I think the Commission could prescribe this–whereby they would designate the dedicated acreage, the price, the take, the quality provisions, the same thing you would have if it

[3078]

were a contract so that you could see right at that point, and you would have available and your rate staff would have available when it came to a rate proceeding of that pipeline company a document to see that the pipeline company is acting in accordance with the order of the Commission.

Q. You stated that you have already considered this problem. Have you prepared a document of the nature you have described? A. No, because we don't have a division, you see. We have a subsidiary where we file just the same as an independent producer, and everyone gets copies of the contracts. That is something I think would have to be worked out. All I say is I recognize, as you do, that there would be a problem.

Q. But there are pipelines in your group that have producing departments? A. And I haven't discussed it with them. I should have, but I haven't.

Q. Would there be any need for an upward and downward Btu adjustment for pipeline produced gas? A. From our standpoint only if there were an upward and downward revision in that area for independent producers. In other words, whatever you come up with, if you come up with a specific area where the final order of the Commission provides for upward or downward adjustment, then in that same area the pipeline produced gas should have the same provisions.

[3079]

Q. Wouldn't the piepline company be interested in maintaining a relatively good Btu content of its gas without the additional incentive of an upward or downward Btu adjustment? A. No, it doesn't make that too much different. As far as Btu's of the gas, that is a pipeline problem, and we have gone along for years with certain Btu's in our stream and we will in the future.

Keep in mind the question I answered of Mr. Reifsnyder about so much of this gas will be jointly produced in the future. You will probably find very few instances where there won't be a contract with an independent producer that provides the same provisions, and the royalty owners and everything will have to be comparable. But we are not proposing any change at all, any difference between us and the independent producer.

Q. If the gas is jointly produced in the future, say in a field in which the pipeline producer controls 15 percent of the production, would the pipeline be getting any more flexibility from that production than it would be getting from gas purchase contracts related to the remaining production in the field?

MR. SHIBLEY: Mr. Dietrich, you are assuming on-system delivery from this supply to the pipeline which has the 15 percent participation?

MR. DIETRICH: That is correct.

[3079]

THE WITNESS: If we had a 15 percent interest in a field, we would have no flexibility from that because you would have

[3080]

to go with the 85 percent in fixing the allowable determination. You couldn't call the allowable determination with a 15 percent interest.

Flexibility is a factor, but I want to say this: I don't think it is a real important factor. You do get it in the instance where you may control a whole field or where you control 80 percent or 75 percent, where you really call the shots on fixing the allowables, and it helps and it can help down the road to a great extent, but the flexibility would only occur where you really control the field either through a hundred percent ownership or really enough to call the shots on fixing the allowables.

BY MR. DIETRICH:

Q. Have you entered into any joint interest activities in the Southern Louisiana area or the Texas Gulf Coast area to date? A. Oh, many. Hundreds.

Q. What is your typical interest in terms of percentage? A. On shore we try not to go below a third interest. Most of them are a half. Off shore we try to go not below 20 percent, but most of ours are 25 to 33 percent, the difference being that the off shore is much more expensive than the on shore.

Q. You are talking about Texas Gas Exploration Company? A. Yes, sir. In our group I think most of them are in

[3081]

just about the same category that I have talked about.

Q. What rate would you recommend be permitted for pipeline production in areas for which the Commission has not yet established area rates that are operating under in-

line rates or guidelines? A. My answer to that would be this: I don't want to say a rate. Again I go back and repeat that we are asking to be given the same treatment that the independent producers are given. This is whether the area rate has been established or whether it hasn't.

If in a particular area the area rate has not been established, then, whatever the guideline or the in-line, whatever the rate the Federal Power Commission would allow the independent producer during that period would be the rate they should allow us.

Q. In the areas I have mentioned, then, where the area rates have not been established, you would recommend that the Commission permit an in-line rate, and if the in-line rate has not been determined, you would recommend the guideline rate, and that would be your recommendation? A. Yes, sir.

Q. Turning to transcript page 709, the last three lines on that page discuss fair field price treatment. Wouldn't the effect of your recommendation concerning in-line rates be to accord fair field price treatment?

[3082]

A. Yes, but that was not the intent of the testimony. I was trying to point out that we were not asking for a fair field price approach where that fair field price might exceed the area price fixed by the Commission. That is going back to some of the older cases where efforts have been made to have in effect the fair field price. We are not really asking for that. The fact that fair field price would coincide with guideline or in-line prior to the fixing of the area rate would just be coincidental. What I meant was we are not asking for something that would be based on other than what the Federal Power Commission would base its rate.

Q. The substance of your answer being that you are recommending a field price or in-line price so long as it doesn't exceed the Commission's ceiling in a given area.

[3082]

A. We are recommending whatever the Commission gives the independent producer, and if they give him a rate that in effect is the same as a fair field price, yes, but I was just trying to distinguish between what we are asking for and the old concept of fair field prices.

Q. Have you given any consideration to the question of the appropriate cutoff date as between leases acquired in the future and gas produced on such leases and existing leases and gas produced on those leases? A. Yes, very much. First as to cutoff date itself, regardless of whether we are talking about leases or something

[3083]

else, as far as cutoff date itself, we feel that certainly the cutoff date should not be any later than the date these proceedings were started. We have tried since 1963 to get a determination from the Commission on this question that is the subject matter of this proceeding. As far as cutoff date, we feel it shouldn't be after this proceeding is finished but it should be no later than the date it was started.

Second, the Commission in its order setting this hearing specified the Phase I operation to be determined by a date of acquisition of leases. We do not agree with this. We think it should be either the date of first discovery, the date of first delivery, or the date of the contract, one of those three things.

Q. Mr. Elmer, in light of your testimony that pipelines experience a lesser degree of exploratory drilling that the independent producers, how could you justify retroactively applying the area rate to the date of first discovery, the date of first delivery or the date of contract? A. This has no bearing on the answer I gave.

Let me give you an example. Off shore it may take five years or longer from the date of acquisition of the lease to the date of exploration of the field, development of the field, and then finally selling the gas. For example, there are many leases now that are owned by many companies

that were acquired in the 1962 sale, and this is 1967. The great preponderance of

[3084]

those or the great majority of those have never been marketed and most of them really haven't been explored. They are being held by, say, one well, and the exploration really hasn't started. It is going to be a very expensive process to carry on the exploration work and the development work, and it doesn't seem right solely because these leases were acquired in 1962. With all of this work that has yet to be done, that we shouldn't have the same treatment as the independent producer has which has the same lease under the same conditions.

Q. Concerning the question of risk at transcript page 715, line 7, you state that the production of gas and oil by a pipeline has the same riskiness as it is for the independent producer.

In making that statement, you have reference solely to future production and not past production, is that correct? A. The only thing they have asked me to testify to here is future production, so I would have to answer that affirmatively.

Q. In light of the fact there has been a lesser degree of exploratory drilling by pipelines than there was by independent producers, it would appear that the risk has not been the same, is that right? A. That is apples and oranges. There are many reasons for that, and you will get into that in your Phase II, as to the various reasons, but the risk is the same. I will say this, the risk has always been the same.

[3085]

Q. You stand by the testimony, though, that there has been a lesser degree of exploratory drilling by pipelines than by independent producers? A. Oh, my, yes.

[3085]

Q. Do the leases of pipelines normally carry serial numbers, Mr. Elmer? A. I am not a lease man. I assume they have all got numbers. I don't know. I don't know how leases work.

Q. How do they work for Texas Gas exploration? A. I don't look in their lease files. Just as long as our attorneys say they are valid, that is all I care about.

Q. If the Commission were to adhere to the indicated treatment of applying area rates to gas produced from future acquired leases, the Commission could determine, I assume, the serial numbers of existing leases and the serial numbers for leases acquired in the future; would that be your understanding? A. Do you mean could they have a workable method of distinguishing between dates of acquisition?

Q. That is correct. A. Oh, sure. They are recorded. When you get them they are recorded in the courthouse, and so forth. You have got a date of recording. The serial numbers--I don't know how it works, whether it is by States or counties. You take a company like Humble, I don't know how in the world they keep their leases.

[3086]

Q. I have in mind a pipeline rather than an independent producer. A. The same problem. But you can identify them. I don't know the mechanics of it.

Q. Turning to transcript 710, the second answer, could you describe how pipelines and independent producers jointly acquire a lease in an off-shore tideland area, the mechanics of it? A. Yes, sir. I will give you a specific example.

In 1960 the industry knew there would be a sale coming up in the next couple of years of off-shore leases. Out in this thousands of miles of water there is this area under it, and we knew before the sale that everyone would be given an opportunity to nominate various leases that they would like to put up. Before that nomination could take place

you had to make a geophysical determination of where there might be some possible structures that would produce gas or oil. This is a very expensive process, of going out into the Gulf with shooting boats, shooting out this area, interpreting the shooting, and so forth. So four companies in our particular group said we will pool our resources, one independent producer, three pipeline companies; we will pool our resources and we will carry on what was a million dollar shooting program. So we put in $250,000 a piece, and we spent a year running boats back and forth across the Gulf, getting the geological data, interpreting

[3087]

that geological data.

Q. This is the G. and G. phase? A. This is the initial phase, your geophysical look, first.

Q. You haven't acquired the lease yet? A. No. The sale hasn't come up. Now, we interpret and we find there are several different areas that we think we would like to have leases on. Then we send into the Department of Interior, as does everyone else, some sort of a nomination form saying we would like to have these areas put up.

Then there comes a sale, and before the sale they announce the various areas that are going to be put up for sale, and then sealed bids are submitted. Before the sealed bids are submitted, again the four partners independently have their geologists now take that geophysical data and make a geological interpretation on what they feel might be found, what the possibilities of discovery are, what the sand thickness may be, what the production per acre-foot may be.

After they make their geological interpretations, then the geologists get together to see if they coincide in their thinking. Then, they turn this into an economic omputation as to if all this happens, if we find this gas or if we find this oil, and if we sell it for so much an Mcf or so much a barrel, it costs this much to drill a well, first of all you have

[3087]

to drill so many exploratory wells to see if it is there, then you have

[3088]

to turn around and set platforms and drill all new wells for production, what is all this going to cost, and on this basis they make a determination of what they think they can bid for the lease.

Then the four of them bid, and let's say they bid again for a particular lease two million dollars. There is one lease that went as high as 32 million dollars in this last sale. Then for the two million dollars they each put up—I think you have to put up 20 percent of the bid. Some of these folks, such as Mr. McCorkle, know this better than I, but I think it is 20 percent. You put that in. Say you are the successful bidder. You each put in the balance; now, you have each put in another half million dollars into it.

When you started this you determined that one of the partners was going to be the operator under the venture. Now, the lease is purchased. Now, you have five years to drill a well on that lease to hold it. So the operator now makes plans. He goes out and leases a rig, and he does some shooting, more geophysical work. Everybody shares the cost.

They go out and drill a well, and let's say instead of getting a hundred feet of sand, like they thought they were going to get, they only get 10 feet. So the geologists get back together with the geophysicists, and say we were wrong, we should have drilled a mile or a half mile in a certain direction. If you get any production you can hold the lease. You don't have

[3089]

to give it up. You can call in the representatives of the Department of Interior and show them what you have, and they say that is enough production to hold that lease. So

they hold that lease. So now they go out and test several sites this same group bought, trying to conserve their money because they only have so much to spend. Then they will come back in a couple years and they will move over to the east, they will get another 10 feet of sand. They were wrong again. The geophysicists say it should have been another direction. They will drill in another direction and they get their 100 feet of sand. Each one of these you split one-fourth, one fourth, one-fourth, one-fourth. The pipeline company says you might have something there. The pipeline participants in the venture might say "We would like to have the gas."

The next step is now you have to set a platform and drill wells to actually produce the field. So they set a platform, and then they go in and drill a series of wells, maybe two, three, or four directional holes off the platform, and they have to set two platforms. Finally it is hooked up, and so on.

Through this whole area all of those costs are split in my example a fourth, a fourth, a fourth, and a fourth. The operator enters into a contract to sell the gas, and, to make it simple, let's say it is sold to a party that is not in the venture. When the proceeds come in they take the gross amount of the proceeds, they deduct the operating cost and split it, a

fourth, a fourth, a fourth, and a fourth. This is a typical type of operation.

Q. You are saying it is typical not only in off-shore Southern Louisiana but anywhere in the United States, and in other cases it would be a private individual rather than the Government who would be the lessee? A. I have to qualify it, not everywhere in the United States. Everywhere where you have expensive drilling. For example, we operate in Kentucky where we find gas at 2100 feet. We don't need too many partners on a deal like that. It is

[3090]

where you are in expensive drilling, and again I keep excluding the area that these folks operate in because I am not familiar with San Juan, but basically in Texas and Louisiana, this is a typical type of operation on-shore or off-shore. The on-shore ones will usually have one partner. You don't have many with two or three or more. The off-shore you will find them with more than one.

They are coming up with a Texas sale next spring, and this same process is starting over again.

Q. What have been the joint lease acquisition expenditures by pipelines in the off-shore Louisiana area? A. I think we could get the information. It would be very difficult to get. I can't even tell you offhand. Just shooting from the top of my head, I would say our company has probably spent 12 million dollars off-shore so far. It ranges

[3091]

between a quarter and a third interest in some 170,000 acres.

Q. Are these expenditures that you have mentioned, the 12 million dollars, solely for lease acquisition or does it include the geophysical and geological as well? A. Everything I described.

Q. You don't know what it would be for the lease acquisitions alone? A. No. You could get this. I can get you a map to show you all the leases off-shore.

Q. I would be particularly interested in the joint lease acquisition expenditures of the pipelines where they enter jointly with independent producers.

MR. SHIBLEY: Let's see if we can't come up with something.

THE WITNESS: I think we might find it. It is not going to be easy.

BY MR. DIETRICH:

Q. Turning to transcript page 712, line 7, where you state the consequences of not giving equal treatment would result in reduced quantities of gas reserves available to the industry

since we are talking about a significant number of pipeline and affiliate producers.

Are you including El Paso in this pronouncement? A. I am not talking about any specific company. I am saying this, that the only way to find gas is to dig a hole in

[3092]

the ground, and we have got to give everybody possibly all the incentives we can to dig as many holes as they can. Not just the producer. I would like to give the same incentive to the distributor.

Going back to my answer to Mr. Reifsnyder's question, I think if we do not get the same treatment as the independent producer that from that point on, off of that price on the down side, there will be less wells drilled than there would have been had we gotten the fair treatment. There are a lot of pipeline companies involved. I am not talking about our group. I am taking the number of pipelines that are doing this. I am just stating as a general statement if you take all the pipeline companies involved, and you diminish the incentive to drill these holes in the ground that it will have an effect on the gas reserves that otherwise would have been had we had more people drilling, more wells.

Q. Just how much gas are we talking about, Mr. Elmer? What is the current percentage of total domestic reserves owned by pipeline producers? A. That is not what I am talking about. I am not talking about–first, I can't answer that specific question, but I am here to talk about what is going to happen ten years from now. I am not talking about what the situation is today. They haven't done this to date. We have had pipelines that have been active in the drilling business that have gone out of it completely. We

[3093]

have other pipeline companies who, going back 15 years, who were very active, who are not too active today. We

have these that haven't gone in at all. So what is today is not what we are talking about. I am trying to cure what is today. We are looking at what it will be 15 years from now. There is no answer to your question on that. It is looking into the future.

Q. Assuming that the pipeline producers do have about seven or eight percent of the total domestic reserves in 1962, are you expecting that under your area rate recommendation that they would merely increase their percentage position? A. I am absolutely convinced that had the pipeline producer had the same incentive prior to 1962 all the way back that the independent producer had had, you would have had a much higher figure than that in 1962.

Q. Your recommendation is that they be accorded area rates in the future? A. I am not worried about what we have got today. My problem is what we are going to have 20 years from now. I say that give them every incentive you can, everybody, to go into that business, so that the pipeline company, the distributor if he wants, will have a greater and greater incentive and will find a greater and greater percentage of the reserves.

[3094]

Q. If the Commission were to adopt your area rate recommendation, to what extent do you think they would increase their percentage position with respect to total domestic reserves ownership? A. I have no way of answering that question. I am just giving you my, I guess it is, informed judgment, my personal judgment, the fact I know there would be more and it will continue to be more.

Q. Have you attempted to estimate the capital requirements necessary to materially increase their position? A. No.

Q. You are not in a position to state whether or not they would be able to demand sufficient capital resources to significantly improve their positions? A. Yes, I am. I am sure they all could obtain the capital resources to do it.

If you are asking me how much, it is like asking me how much is the Government going to spend in 1980. I don't know. You are talking about a very broad thing.

Q. Does Texas Gas Transmission Corporation project their capital expenditures into the future? A. Yes, but I am not–

Q. For what period of years? A. Let me explain to you, Texas Gas Transmission Corporation, as such, doesn't have any production to speak of.

[3095]

Q. I am talking about your wholly owned subsidiary, Texas Gas Exploration A. Oh, maybe a couple of years. We just are able to drill on the basis of the cash we can generate and that that company can borrow. I can't project what is going to happen.

Let me give you an example. As I just stated, there is going to be an off shore sale in Texas next year, the first one. We have never had an off shore sale in Texas. There is a lot of hope that there may be a lot of gas found. If there is, then, it is going to change the whole setup. You can't project what is going to come and where it is going to come and what is going to motivate it, but you know there is gas in the ground and you know it is going to be found. But to try to project when and how and how much and why and what it is going to cost and what is going to happen to drilling techniques, you can't do it. You can do this in the pipeline business. This is why the producing business is so different.

All the things you are talking about you can sit down and do in the pipeline business. I don't care who you are, whether you are the smallest independent producer or whether you are the largest pipeline, the smallest pipeline or the larger independent, you can't project five or six years ahead where you are going to spend your money. It is impossible.

[3095]

Who knew the North Sea was going to be discovered? And look how that has changed the whole aspect. These are the things

[3096]

that you don't know.

Q. What I was attempting to do, Mr. Elmer, was to determine the dimensions of the problem that we are here dealing with, whether or not the Commission can expect siginficant production of gas reserves from this segment of the producing industry in the future, and if they are now seven percent, will they likely grow to some larger segment of the industry in the future, and you state you do not know the answer to that? A. No, I didn't. I said to you that had they had the same treatment as the independent producer, they would have been substantially larger than seven percent, in my opinion. I think that every pipeline company will be interested in doing all they can in this area to try to supplement their gas supply, get new gas, and I think you will have more drilling, substantially more drilling if they get equal treatment than if they do not. If you want me to say it is going to be 20 percent instead of seven, no one can say this. But I say there will be more incentive and more drilling.

Q. And you don't know the degree to which capital will be required to substantially increase that percentage? A. It requires capital, but it requires capital to build pipelines and it requires capital to do everything else. These are all big companies. They will find ways if the incentive is there to do it.

They certainly can't go out and sell equity capital or sell

[3097]

future debt capital–and you are talking about future debt capital; you are not talking about some current average debt cost, we are talking about future debt. And you see

what happened yesterday when U.S. Steel sold a quarter of a billion, and Tennessee pays 6¾.

MR. TALISMAN: Six and one-quarter.

THE WITNESS: It is too much.

This is what we are looking at, the cost of production, future debt cost, future equity cost, and as long as they can get a price that will let them do it, it doesn't make any difference whether you pay eight percent for your money or six if you get the right price.

I think through proper regulation, taking into account demand and supply, that funds will be created to do this job that you are talking about. Just give them the incentive, but the incentive has to be there in an economic form. I don't think you have to say where is the money coming from. It will come from selling the product.

MR. DIETRICH: This is a convenient breaking point.

PRESIDING EXAMINER: We will now take a recess.

(Whereupon, at 11:15 a.m., a recess was taken until 11:30 a.m. of the same day.)

PRESIDING EXAMINER: The hearing will come to order.

BY MR. DIETRICH:

Q. Turning to transcript page 713, Mr. Elmer, lines 11

[3098]

through 13, do you know of any instance where the Commission has disallowed production costs in determining expenditures having been prudently or imprudently expended? A. To my knowledge, they never have.

Q. Has the stockholder of pipeline companies in the past received adequate protection under cost of service treatment? A. I can't answer that question. I can only speak for myself, and our production is relatively new. I just can't speak for the other pipeline companies. I think this would be a Phase II question.

Q. Turning to transcript page 718 where you indicate that the significant discoveries by a pipeline or an affiliate in an area will generally result in stepped up exploratory

[3098]

work by other producers. Isn't this an infrequent situation in light of your testimony that pipelines engage in a lesser degree of exploratory drilling than independent producers? A. When I say "other producers", I mean other independent producers.

I can give you two specific examples of this. In the late forties Texas Gas purchased a substantial amount of gas from the Carthage field and built a pipeline from Northeastern Louisiana into the Carthage field, and the Carthage started falling off. So we set about to try to find something to fill up that line. In, I would say, the early fifties we were able to

[3099]

acquire what looked to be a semi-proven field or part of a semi-proven field—Mississippi River Fuel acquired the other part—called the Sligo field that had production in a couple of sands, one called the Petit and one called the Jeter, which are shallow sands. There wasn't much activity around there. It was some Government land and it sold on a bid. We went in there and Mississippi and ourselves decided to see if there was some deep production in there, which nobody had anticipated. We drilled a couple of test wells and found some deep production in a deep sand called the Cotton Valley, and immediately other producers were in there drilling in that area.

Even a more recent example: There had been very little drilling for gas in Kentucky. We want in there a couple of years ago and drilled into a real good gas field, one that nobody thought would ever exist, and since then even the majors, not just the small independents, are up there leasing and drilling all over the place, and we have built production up as a result of that well. We are now producing up to 60 million a day out of Kentucky fields where there was practically nothing there three years ago, and it was all motivated by going in because we wanted to see if we could find some production at a point in our pipeline where it would be helpful.

Q. What volume of natural gas reserves have been discovered by pipeline producers in the last decade? A. I have no idea.

[3100]

Q. So we have no measurement of the matters discussed by you in the first three lines of transcript page 718? We have a few isolated examples? A. Yes. If you will look at the first three lines, I say, "Significant discoveries by a pipeline in such area will." I don't say they have, I say they will. I am talking about the future. My whole testimony is geared at the things to me that are important in granting equal treatment to the pipeline producer. You can't by past figures prove anything to speak of as against what we are asking for here. We are saying we, to the best of our ability, are trying to tell you what we think the situation is and how we think this can help, but the fact that they haven't had the treatment in the past and that there has been problems in the past, the companies have gone out of business in the past, you can't go back and say because this has happened something else is going to happen. I am saying what I think will happen.

Q. Concerning transcript page 718, subparagraph (c), which would be lines 4 through 8 inclusive, where you talk about production operation providing experience of value to the pipelines in dealing with independent producer sellers, to what extent has this kind of experience enabled Texas Gas to obtain natural gas prices in gas purchase contracts at a level less than the ceiling imposed by the Commission? A. It has not and will not result in obtaining gas at a

[3101]

lesser price.

Let me tell you what I am talking about. If a producer drills a exploratory well into a certain field and the pipeline knows because of their experience the problems that that producer is going to be faced with in development of

the field and further exploratory work in the field, and you can go to that producer and say I know what your problems are and I can gear my takes in this gas purchase contract to fit your problems because I know what your problems are, he has got a better chance of buying the gas than some guy that doesn't know it and goes in and says you have got to develop it so I have so much proven reserves because I have to have so much of the take to go to the Commission. It has no effect on the price, but it has been helpful, it has been helpful to us. I am sure those people in the room who are buying gas for pipelines know that if he knows the producer's problems and can coordinate their takes and their purchase requirements and their development requirements, it is helpful. It may be the other way around. It may be that they know this producer has a problem where he has to have some higher takes for three or four years to fit a certain problem. If they understand why, it can help them in buying the gas. But this item has no bearing on price, as I see it.

Q. Isn't it a fact that many gas supply managers for pipeline companies are former employees of independent producers and obtain all their needed experience in that manner?

[3102]

A. None to my knowledge. Every one that I know of has grown up in the pipeline industry. There may be one or two, but basically they are men who have grown up as pipeline people.

Q. Turning to transcript page 719, lines 14 through 17, where you talk about the unavailability of uncommitted substantial gas reserves, Texas Gas Transmission Company acquires its gas in South Louisiana and Texas? A. Basically South Louisiana.

Q. And from other pipeline companies who acquire gas in Texas, such as United? A. No. For many years it has been our policy to acquire gas only from independent producers. We have not acquired any gas for 10 years or more

from any pipelines and do not intend to with one specific exception. We have a very major program that is pending before the Commission at this time that we felt it advisable to try to get the gas in one package for that one program, and we had to get that from the pipeline because with the extreme shortage of the gas there were no producers that had it. But our policy has been and will continue to be to buy from independent producers.

Q. By this testimony that I referred you to on page 719 you are not intending to imply, are you, that Texas Gas will not be able to command a supply of natural gas sufficient to meet its estimated requirements for a period of approximately 25 years?

[3103]

A. No, I am not implying that at all. What I am trying to say is this: I know, and we all know that have had any experience in the producing business and even in the pipeline business, there are substantial quantities of gas yet to be found. It is going to take money to do it, it is going to take incentive to do it. I am saying here today that there are no substantial gas reserves available in that area for acquisition.

I just want to give you an example. Here is a company, Texas Gas, selling a half trillion feet a year, and we are actively working and negotiating to day on eight packages of gas, and the largest single one in the eight is 25 billion cubic feet of reserves. There are just no major on-shore ones today. There are a few off shore, very few, some are far off shore, but what I am trying to point out is there is as far as available gas today, discovered gas and developed gas, it is just real slim pickings.

Q. But you still do not anticipate any difficulty with respect to acquiring your own gas supply needed for estimated requirements for the next 25 years, is that correct?
A. It is based on one thing, sir; it is based on how realistic the Federal Power Commission is in fixing the price for the consumer. If they are realistic and give him an incentive to find it. If they don't, I think we all have problems.

[3103]

Q. Have you advised the Commission in any Section 7

[3104]

certificate proceedings that Texas Gas is encountering any difficulty in securing necessary gas supply to support their proposed expansion? A. No. We have been able to and always have been able to acquire enough. What I am telling you is it is getting tougher and tougher and tougher. This may happen three years from now. But we and the other pipeline companies have been fortunate to get it. Five years ago, this was the other way around. There has been this change in trend, and I am just trying to point out what the change in trend is. But the gas is there. There is no question. No one is worried about running out of gas in the ground for longer than any of us will live in this room. We have just got to get it out.

MR. DIETRICH: Those are my questions, Your Honor.

MR. SIMONS: Mr. Examiner, I have some questions.

I am Morton Simons and I represent Long Island Lighting Company.

BY MR. SIMONS:

Q. Mr. Elmer, you have on a number of instances, particularly in the recent answers that you gave Mr. Dietrich, indicated that you felt that the Commission had to give as much incentive as possible, as much incentive to the people who are doing the drilling. Were you thinking of incentive in terms of price, in terms of price and certainty, or in terms of some other factor?

[3105]

A. In terms of price, money. That is what economics are measured in to the best of my knowledge.

Q. Would it be your position that the higher the price the greater the incentive? A. Of course.

Q. Does that logically follow? A. Yes, sir, up to the point competition plays a part. As we all know, demand

maybe gas can be sold high in my area but it would run you out of business. I say you have to balance the two to the best of the ability of the Commission, but to the extent that they can keep it in balance, then, I would say don't penalize—try to keep the producer's price up as high as possible.

This sounds like a wishy-washy answer, but it is hard to answer. Let's just talk figures. If it is a matter of a producer getting 20 cents or 21 cents and either one of them would do the job, the one cent might make a big difference, or if it is two cents or three cents. I don't know what we are talking about.

I know what is happening to the cost of production. I know to go out in that Gulf of Mexico to drill that well I and supply are really the determining factors in competition. But up to the point the product can be sold economically, the higher the price, the greater the incentive.

Q. Does your advocacy of the Commission's giving the greatest incentive it can mean that you would advocate the Commission's giving the highest price it can up to the point where the gas could no longer be sold? A. No, sir.

Q. Would you explain why not? A. As you know, you represent a client in the east that has a very close competive differential with competitive fuel. I work for a pipeline company in the Middle West that has a much wider spread in the competitive area. I think the Commission's job is to give a price that will give the incentive to the producer to supply all the gas that is needed and still get the gas to the consumer at the most reasonable price. I think those two have to be taken into account and balanced, and

[3106]

told him about, that may be there, was three million bucks invested in the first test made, and I know there are a lot more that aren't productive than are, and I know they have got to go out and drill those wells, and we have got to eventually have as many wells in the Gulf as we have on shore Louisiana. I know each one is going to cost more.

[3106]

The labor cost, the rig cost, everything is going up.

I think we have got to go as far as we can, consistent with our responsibility to the consumer, to give the producer all the incentive he can get.

I am not here arguing an area price case. I am really saying whatever the price is, we just want the same treatment.

[3107]

I don't want to get off into a field I am not qualified to talk about.

Q. In any event, however, there is a relationship between what you are advocating here and what possibly might be in an area rate case in that you are concerned with incentive and you are concerned with a total adequacy of supply. As I understood your last answer, Mr. Elmer, you would want a price high enough to bring forth an adequate supply; you would not want a price higher than that level because, as I understood you, you felt that would not be consistent with our duty to the consumer? A. No, I am not saying that. I am saying that I believe after all the testifying in court cases and settlements are over, I believe that the Federal Power Commission is going to fix a price, whatever it may be, from time to time that will keep the producer in business and keep him looking for gas. I am not saying what the level should be. This is a much bigger thing than us. We are a small part. As he pointed out, we were only seven percent in '62. I hope we get more and I think we will.

This is only a matter of saying two people doing the same job have got to have the same incentive. I don't want to talk about what the price ought to be. This is going on right now in 61-2.

Q. But we do get to the question of whether there should

[3108]

be two people doing the job or one person? A. I think there ought to be 20.

Q. There are two types of people I guess really. And the reason you think there ought to be two types of people is so there would be more exploration, as I understand it? A. Exactly.

Q. More discovery and more dedication to the interstate market? A. More dedication to the whole American consuming public.

Q. If we were to assume that the Federal Power Commission in fixing an area rate for independent producers only fixed a rate at a level that would assure an adequate supply of gas for the consumer from independent producers only, would there be any reason, either in this proceeding or in any other, why the Commission should concern itself with providing an incentive to pipelines to engage in production to discover amounts of gas additional over and above that which independent producers would otherwise find? A. Yes. Let me give you a reason for that answer.

I started in the production business in 1952. This is '67. That is 15 years ago. When I started, I went to Houston and I went to Lafayette through that year, and the cities were just blanketed with offices of good small independent producers, and most of them are out of business today. This is happening in Texas. I know the TIPRO people in their recent testimony that

[3109]

I read pointed out the same thing. The little guy is going out. They have been responsible, Mr. Simons, over the years. It hasn't just been the Humbles, the Shells and the Texas Companies that have found this gas. These little independent producers over the past 30 years have been a big factor. But because of cost, because of cost of production, deeper drilling, they are going out of business, they are being absorbed. Frankly, I think we need some more peo-

ple back in the business. I don't believe anybody can say that at any price you can be absolutely assured—in fact I know this—there will be an adequate gas supply for the growth of this country as it is projected.

I think Humble can do all they can and the Texas Company and all the big ones and we still need everybody else that we can to get into this business. As far as small independent producers, as far as pipelines, there is no way to say that we can give a price so 25 companies can supply this country. Knowing the gas business as I know it, I don't think this is possible.

Q. Then you are saying that you do not believe, and it is a premise really of your testimony here, that the Commission can, no matter what it may intend to do, you don't believe the Commission can in the area rate proceedings fix a price that will provide an incentive to the independent producers to bring forward and dedicate to the nation's consumers an adequate supply of gas?

[3110]

MR. SHIBLEY: Mr. Examiner, I object to this question. I think it is getting to somewhat of an argumentative stage. Mr. Elmer has contributed to the understanding as to how he views this problem. I don't think his function here is to try to demonstrate exactly how the Commission is to make area rates in the independent producer proceedings nor is that an issue here. I really think we have reached the argumentative stage, and I say that not critically at all. It is an interesting subject. It is one which is engaging all of our attentions in those area proceedings.

MR. SIMONS: Perhaps I can reframe the question. I don't mean to become argumentative with the witness. I do think the two proceedings are interrelated, at least interrelated in this witness' testimony, and if I may I would like to withdraw my question and submit another, reframing it.

BY MR. SIMONS:

Q. In preparing your testimony, did you go on the assumption that whatever rate the Commission might fix in the area rate proceeding for independent producers would not elicit an daequate supply of gas from independent producers alone to satisfy this nation's needs? A. That is a hard question to answer. It is like saying how high income taxes will have to go to take care of Government expenditures. I just don't know. I feel that the independent producer is going to exert his efforts and spend

[3111]

his resources to the best of his ability to find all the natural gas he can if he is given the incentive to do it, but this is not a problem of planning a pipeline to serve New England and anticipating exactly what the growth is going to be in New England and figuring the diameter of the line. I go back to this is a real risky business, and a big company can have a lot of hard luck, too, and the price doesn't have anything to do with their luck. They can have some real bad luck, all of a sudden there will be a slump-off in production. I say we ought to be in there, too. If there are enough people in there, one is going to offset the other. It isn't something like manufacturing a product, where you say if you give enough money, I will make as many automobiles as you need. Their effort will be there, but it takes more than effort to find this gas. I think all the Commission will do is to say we hope you will find it, and all the producer can say is we will do our best to find it, but knowing what production is, what a risky business it is, and how it can be so risky for major companies, I say we all ought to be trying all we can. It wouldn't bother me if we had an overproduction, I will tell you that.

Q. Even at the expense of a higher price? A. You are trying to figure this down, and you are saying if we give them this price, two and two makes four. Well, two and two doesn't make four in the production business. This is the whole problem you and I are having in this.

[3112]

If you were talking to me aobut a manufacturing problem or a pipeline problem, we could see eye to eye, but we can't, because there is a third element in here that I have been talking about that neither of us can foresee. We want, you want and I want, the consumer to have all the gas they need as this great country grows. So let's do everything we can to be sure it is there. I don't believe you can cut it as close as you are trying to cut it.

Now, I will go back and answer your question, with all that in framing my testimony, no, I do not think that the independent producer by himself, regardless of his size, can assure us that he will have the gas whenever we need it in the volumes that we need it. All they can assure is they will do their utmost to try to have it there.

Q. Let's broaden that. Assuming that the Commission were to set an appropriate price in the area rate proceeding and were to in this proceeding allow the pipelines the same area price or prices, would that, in your opinion, assure an adequacy of supply? A. No, but it would assure more people trying to get it.

Q. Would it assure a more adequate supply than if the Commission fixed an area price in the area proceeding alone that it thought was geared to assure an adequate supply? A. I don't understand that question. Would you try again?

[3113]

Q. You indicated before, Mr. Elmer, that regardless of what the Commission did in the area proceeding there might still be a gap, as I understood your response– A. That is correct.

Q. –in the amount of supply available. I think you indicated that regardless of what they do in the area proceeding and regardless of what they do here also there might still be a gap. A. That is right.

Q. Is there a difference in those two gaps or are they of the same general nature? A. Oh, no. There is not as much

of a gap. The more fellows who are drilling exploratory wells, the smaller the gap between supply and requirements is going to be.

Q. If you were working in the independent producer field alone, the higher price you might allow than otherwise, the smaller the gap would be? A. I think that is true because there would be more incentive to drill more holes.

Q. In light of the riskiness of this business, and the fact you say even a very large company could go four or five years without finding anything– A. Anything material.

[3114]

Q. Without making much money, let's say. Could you explain your statement that a producing subsidiary of a pipeline company, the fact of its existence may be looked upon favorably by security analysts and investors? A. First, it is. I have several releases here, statement after statement, and the reason is hope springs eternal in the mind of the investor. He knows what he is looking at in a pipeline. He has seen a continual decrease in earnings on equity in a pipeline, in a straight pipeline operation. But he knows that in the production business if you are successful there is always a chance of making an oil discovery or making a gas discovery where the return on that investment at least has a chance of being something material to him, something to bolster up. I can tell you in our own company this year our pipeline earnings are off, I believe they were off 15 cents a share. It was made up by our production company because they had a successful year. They fortunately found some good gas. This is what the investor looks at. It is why we are all diversified. They looked at it as something that is not going to be squeezed down and down and down as our equity earnings have been. This is the reason that service after service points out that this is good, these people are in the oil and gas production busienss

[3114]

You can't stay in it and be unsuccessful for four or five years. You have got to be successful. If you work hard and watch your expenditures, and so forth, you can have a fair

[3115]

return, particularly if you run into any oil, because there again that is more profitable than the gas is.

It is just a feeling in the minds of the investor that they like to see a pipeline company that is diversified and diversified into the oil and gas production.

Q. There would be this investor and security analyst advantage in a production department even if you were only looking for oil or even if what you primarily discovered was oil or even if you were geared to oil and your gas was salable at some lesser price than otherwise, would there not be? A. Yes, but you can't be in half a business. It is hard enough to find hydrocarbons of any kind. I don't think any company could afford just to say we are just going to try only for one type. If you get a chance to get a good lease–you see, you need these revenues. We, for example, are primarily interested in finding what gas we can in the area of our pipeline. We have not to have sources of funds to do it. This company supports itself. It is the revenue from the sale of present hydrocarbons, present oil and present gas, that gives you the money to drill for tomorrow's gas and oil. You wouldn't want to just run a one-way street. You have got to put it in one package. I have never heard of such a thing as you are talking about.

Q. I was thinking you might be in the gas and oil business and the fact that the oil business was as you suggested more profitable and that the prospect of a substantial profitable

[3116]

strike there in oil would in itself have some of the investor advantage? A. It is the romance, but the romance–you only kid the girl so long.

Q. You have to know when to stop? A. Right. So you have got to be successful. But it has worked out, and I say release after release that you get from your services, they like it.

As I pointed out to Mr. Reifsnyder, it really only affects your cost of equity capital, but on equity it is important.

Q. Incidentally, you mentioned the decline in earnings under pipeline operation, is that a long-term trend or something that just happened last year?

MR. SHIBLEY: As interesting as the subject is, I don't think the area of what is Texas Gas Transmission Corporation's long-term trend in earnings is going to be of material benefit to Your Honor. I am sure that Mr. Elmer would be pleased after the hearing to give Mr. Simons a pretty good rundown on the growth of his company, which has been struggling through these years with an exploration company which is in some uncertainty but is being treated fairly well right now, and we hope we can get a decent result out of this case.

MR. SIMONS: I thought that point was relevant, but if it is not, I guess that is all right.

BY MR. SIMONS:

[3117]

Q. Is your company more active in drilling and exploration today than it was ten years ago? A. Oh, yes, sir.

Q. You indicate in part of your direct testimony that you are concerned about a reduction in the gas available–new gas supplies available–and you note that a portion of that goes to the intrastate market in any event? A. Where is that? Would you help me?

Q. I think it is 719, down about two-thirds of the way. Then on page 720, about the middle of the page. Let's take the quote at page 720, and I will read it, as it is a short one.

"Under conditions of shortage most available gas would be channeled into unregulated markets."

[3117]

Isn't it a fact, Mr. Elmer, that so far as your pipeline is concerned in its general areas of supply, the principal area you are concerned with would be off-shore Louisiana? A. The whole Louisiana Gulf Coast and off-shore; yes, sir.

Q. Have you received any advice from your counsel that off-shore gas can be sold interstate or intrastate? A. No. I am not talking about off-shore. I say on-shore or off-shore. Frankly, we are more interested in on-shore because of the tremendous gathering costs offshore. We made a study, this is a company study, and it showed that for '64–I think it has gone up–there was some 22 percent plus of the

[3118]

gas that was produced in Louisiana that was marketed in Louisiana. There was 51 percent of that in Texas. I think the greatest example of this that you have all seen recently is in the last year the greatest single undeveloped and unsold piece of gas that there is maybe since the Carthage field in the form of the Katy field, came on the market, and it is something that interstate needed badly, and to the best of my knowledge every foot of it went intrastate. This concerns us, the pipelines. We don't blame the producer. He has an economic problem, too. But when we see a field with some seven or eight trillion feet of gas go into the intrastate market simply because the interstate market can't offer the same advantageous price advantage, it concerns us. A lot of that offshore gas, Mr. Simons, is going to be sold right in the Baton Rouge-New Orleans area.

Q. Are you assuming any change in law, like the current Long bill, or are you assuming that would be true even under existing law? A. I don't know anything about the current Long bill. I just know when I fly an airplane from Baton Rouge to New Orleans and see the plants that are coming up and taking the gas they are taking it scares me to death.

Q. You list certain problems that the pipelines have had in getting into the– A. Where is that, sir?

Q. Page 712, thereabouts. And I think you have adverted

[3119]

to the uncertainty that has characterized a pipeline trying to determine whether it should go into production or should not go into production, and you have listed certain advantages of providing the area price, which you call parity treatment. In the event that the Commission were to adopt something less than 100 percent parity, let's say 90 percent parity, which of the advantages that you show on pages 717 and 718 would disappear, which incentives would disappear? A. None. None would disappear, but "D" is the one that would vary, because as I pointed out earlier in my testimony here today that when you start moving off the area price downward with each percent, a penny or whatever you are talking about, that you move off of it, it is going to create less incentive on the part of a pipeline as to the magnitude of the production business they can be in. As the magnitude of that goes down, then that in turn could have an effect on the interest of analysts and investors, and so forth. I would say none would disappear. Of course they would all disappear if it got so low the company decided they couldn't be in the business at all.

Using your example of saying it was 10 percent off, it would decrease the incentive for people to be in it, and, in turn, have an effect on the fourth item on page 718.

Q. You have mentioned the advantages of a pipeline being in exploration. What in your opinion are the advantages? In

[3120]

your opinion, are there any disadvantages to a pipeline being in exploration? A. There are no disadvantages of a pipeline being in exploration if they can be in exploration on the same basis that their competitors are.

Q. There is a disadvantage to their being in? A. Of course, if we have to be in the business—this is the whole

purpose of our being here today—if we are going to be in it and the price that we got for our product had so much of a differential—in other words, you could fix a differential. I can't tell you what it is, I don't know. All I can do is measure the enthusiasm and what it would take to get into the business, but the more you are in a business and you are selling a product at a lower price than your competitor is, that is a disadvantage.

There are other advantages, as I have pointed out. There are advantages to being in the business. But it is a disadvantage if we both have identical expense and I have got to sell mine for 10 cents less than you sell yours. I am saying that is the only disadvantage I can see.

Q. You sell your gas in the Cincinnati area for less than one of your competitors, do you not? A. That is right.

Q. Is that a disadvantage to you? A. No. The reason I can sell my gas for less than my

[3121]

competitors do, and I am getting way out into my competitor's field, is not because we have similar risks and similar problems as a producer does. We just happen to have a system that is so situated and so built and not as long as the other, and many other things, and we are both operating efficiently, but we are not the same. We don't have the identical problems facing us as do two independent producers.

Q. But like two independent producers you are selling the same product? A. Like two producers.

Q. Like two producers, you and your pipeline competitor are selling the same product at the same place at a different price. A. Well, you are a pro in this rate structure business, and I am sure you know all of how it works. I just don't want to get into what the rate problems of one of my competitors are.

Q. I thought that was one of your favorite topics. A. It depends on where I am expounding on that.

MR. SHIBLEY: I might say that competitor happens to be a part of our group, too, and we would have to provide equal time. In the interest of efficiency, I am glad to see that Mr. Simons has moved on to the next area.

BY MR. SIMONS:

Q. You state that one of the advantages of a pipeline being in production is it helps the buyer in effect to understand the

[3122]

seller's problems and be in a position to negotiate with him on somewhat more advantageous terms than a buyer who was not also in the seller's business. A. I didn't say on more advantageous terms. I said it permits you to buy his gas ahead of another pipeline who is trying to buy it that doesn't understand his problems.

Q. Would the same be true of all vertical integration in the gas business at least? Would it be appropriate or desirable as to this reason, say, for a distributor to get into the pipeline business because then it would better understand the needs and operation of its independent pipeline supplier and could negotiate with it? A. I think it would be great.

MR. SHIBLEY: I think I will object to this, Mr. Examiner. I still feel that it is a philosophical question which is of interest to all of us who are students of the regulatory art, but of very little utility to Your Honor and the Commission in deciding this case, and Mr. Simons is intellectually oriented, but I don't believe this is the occasion for these questions. I think it is the first time I have ever objected to three of Mr. Simon's questions in one day. But these are all philosophical.

[3122]

PRESIDING EXAMINER: Mr. Simons happens to raise a question which was also in my mind, but I wasn't going to ask it. If the witness has an answer, I would like him to give it. I am not going to tolerate extended debate. After a while I am going to

[3123]

cut it short, but in the meantime if Mr. Elmer has an opinion on it, he should give it. I kept thinking about the same thing when I read Mr. Elmer's testimony:

Would he say the same thing in relation to a distributor? Perhaps the answer won't help us, but why doesn't he satisfy my curiosity, too?

MR. SHIBLEY: That is all right. I just want to say I am sure that everybody knows that the group has not addressed itself to any such question as this, and I know Mr. Elmer is going to give us a very useful answer to the question, but I don't think that the question of whether or not distributors ought to be pipeliners or pipeliners ought to be distributors should be taken as any kind of a program for 14 or 15 pipeline companies because obviously we haven't addressed ourselves to that.

PRESIDING EXAMINER: Can you comment on the question?

THE WITNESS: I think, Mr. Simons, and I will make it real short, I think one of the greatest problems that the gas industry has in competing with the electric industry is the electric industry has all phases from generation to transmission to distribution under one management, and I think that a great deal of the bulk of the problems that have taken all these years of testimony, problems before this Federal Power Commission, have been because of the lack of understanding of each other's problems. I think if it were physically possible to put them all into one package you would have a lot better operation. I think if Long

[3124]

Island Lighting were in the production business they would have a lot different look at the producer. I believe if some of us were in the distribution business it would be a great thing for the industry.

BY MR. SIMONS:

Q. Would the same apply forward, the producers going into the pipeline and distribution business? A. Yes, sir.

MR. SIMONS: That is all I have.

I would like to note, although the point has been passed, I hope the Commission is intellectual, too, and I don't concur in Mr. Shibley's implication that they are not.

MR. SHIBLEY: It is not that they are not. Sometimes they are so far advanced beyond the rest of us that we can't understand the basis of it. I was trying to keep this on a factual level.

PRESIDING EXAMINER: I want to go off the record and discuss the length of the hearing today.

(Discussion off the record.)

PRESIDING EXAMINER: On the record.

We are going to recess for lunch and return at 2 p.m.

(Whereupon, at 12:25 p.m., a recess was taken until 2 p.m. of the same day.)

[3125]

AFTERNOON SESSION 2:00 P.M.

PRESIDING EXAMINER: The hearing will come to order.

Who has further cross-examination of Mr. Elmer?

MR. STANSFIELD: I have some.

Whereupon,

W. M. ELMER

resumed the witness stand and was examined and testified further as follows:

[3125]

CROSS-EXAMINATION (Resumed)

BY MR. STANSFIELD:

Q. Mr. Elmer, my name is E.A. Stansfield. I represent the Public Service Company of Colorado, which I am sure you know generally is engaged, among other things, in the distribution and sale at retail of natural gas in Colorado. Public Service has no corporate affiliate with any interstate pipeline or with any independent producer. It purchases substantially all of its gas requirements for it and its subsidiaries which are also engaged in the distribution and sale of gas from Colorado Interstate Gas Company. I think you generally know the company. Am I right, sir? A. Yes.

Q. Some of my questions are limited in the nature of clarifying questions. The first one is going to be exactly that, Mr. Elmer. I would like for you to refer to the transcript at 708, and in the second section of the answer to the

[3126]

question, "What is the basic position of the group with respect to Phase I," and your answer beginning with Section 2, "Price that portion," and I call your attention to the very last clause in that second paragraph. The record reads, "But not in excess of the contract price where applicable."

I have difficulty with it to this extent, and I am simply asking what is meant by contract price in a Phase I proceeding. We have no gas we are talking about. I am asking only a clarifying question. What did you have in mind? A. The only time that you can buy gas today or probably can buy gas in the future at something less than the area price, if an area price is fixed, will be an instance where there is some isolated small field, an isolated field, a one-well field. The pipelines always have had the position where they try when you get something that you really shouldn't hook up but you hook up almost because the producer has gone this far and he ought to get some revenue out of it, maybe a small field, you try there to get

as low a price advantage as you can in a particular contract. This isn't a lot of gas, but it has happened, it happens today, and it will happen in the future.

Many of those may be, even though it is a little 10 million field or five million field, it still may have been the result of millions of dollars of efforts on a big lease which is a joint lease, for example, so, what I am in effect saying is if

[3127]

at any time in the future we are able to contract for gas, and the same will be true of an affiliate, they wouldn't pay an affiliate any more than they would a non-affiliate because then you never have a chance of buying it from the non-affiliate, and many times they are in joint fields. If you enter into a contract for a lesser price, then, whatever happens to the area price after that, it would still be governed by that contract. It is something that doesn't happen very often, but we thought we should cover it.

Q. And this as you say it is not generally to be anticipated, it would be an isolated situation and probably would not involve too substantial volumes of gas? A. That is right.

Q. Directing your attention now to page 709 of the transcript and the statement about in the middle of the page and your answer that you believe that it is essential that the Commission adopt a policy for all producers which will insure adequacy of gas supplies at reasonable prices.

You go on to say, then, that the Commission must recognize parity of treatment in order to achieve this. Now, with respect to the phrase "at reasonable prices," is it the Pipeline Production Group's position that as a buyer of gas or buyers of gas that the area rates are reasonable? A. I think it is going to have to be everybody's position when the area rates are fixed, if they are fixed, they

[3128]

have to be on a reasonable basis. Reasonable doesn't mean the highest and reasonable doesn't mean the lowest. I think what I am saying is it is the Commission's responsibility, which I know they will carry out, to set reasonable prices for everyone involved, from the consumer to the producer, and that we just want the advantage of those prices whatever they may be.

Q. Then, continuing and in line with the suggestion that has been made by the Staff witnesses at least that until those area prices were fixed, the so-called in-line or guide-line rates established by the Commission would be considered as a reasonable price for pipeline production? A. That is what we would recommend, yes, sir.

Q. Mr. Elmer, you are aware, I am sure, that the Commission in the Permian decision considered the yield on equity as a vital and significant part of the overall rate of return allowed in that Permian case. You are aware of that I am sure, are you not? A. Yes, sir.

Q. When you are asking for a uniform method of treatment, application, under your theory do you include uniform treatment with respect to the yield on equity? A. To me the components that the Commission showed in their final order in arriving at the area price are things I don't agree with. I think there is only one important factor, and that is the price that they arrived at. To the producer

[3129]

that is going out and deciding whether to drill a $500,000 hole or not, you only worry about the $500,000. You don't go back and wonder how they got to it by depreciation and so much allowance for dry hole cost and so forth. All I can say is I hope the price arrived at in Permian, and I am not familiar with the Permian area enough, but I hope it will be adequate to give the producer the incentive he needs. I can't get concerned about how that price is really

justified. I think all these factors are nothing but Johnnie–cone-lately justification really to the price.

Q. Isn't it a fact that how some of these details, as you may call them, are arrived at does have an impact upon the price to the consumer? A. The price that they fixed in Permian, whatever that price is, goes on and it carries out through the producer's rates to the pipeline rates and the distributor's rates and then to the consumer. I can't give you an answer as to whether I feel that one element of a formula is reasonable or not. I could talk for three days on how unreasonable I think some of the other ones were, so it is hard to pick one out. What we are looking at is not whether the rate of return component in Permian as it related to equity was reasonable or not reasonable. What we are saying is if the producer gets 15 cents or 17 cents–somebody has got to tell me, I don't know what the price is in Permian–that is the same price we need in Permian. We just

[3130]

want to be on an even basis with the guy we are competing with.

Q. Price? A. Yes, sir.

Q. Mr. Elmer, I don't know whether you have read the testimony of Dr. Shaffner of the Staff, but to summarize, at least at page 1097 of the transcript, you may recall that he said in effect that debt and equity dollars are not radioactive and hence it can not be shown where they go or from whence they came. He was pointing out in his opinion at least they can not be traced to a particular function. Do you agree with Dr. Shaffner on this point? A. I borrowed a lot of money for our company, and I can trace back where I got every dollar, and if Dr. Shaffner had the same experience he could also.

Q. I think you are answering that you could trace back as to where you got the dollars, and I think that is pretty simple. You can go back to your prospectuses and see who

[3130]

bid your bonds and this type of thing. But can you trace those dollars when they get into your equity and debt dollars that you have borrowed, you know where you got them, into your functions? A. You mean once they are comingled? Oh, you don't trace any particular dollar. Let me say this: You borrow for specific purposes. Take our own production company, when they have borrowed on production payments and they have borrowed on

[3131]

producing wells and borrowed on this, we know where the money has come from, we know where it goes. If you bor- for specific projects, you can trace that. You take the money that is in your general cash account, no, you can't trace that. But you can't make a blanket statement that it is impossible to trace any dollars. That just isn't correct.

Q. Again, I don't want to belabor this point– A. I have a project. We spend "X" million dollars, as does every pipeline, in a year. You spend 30 or 40 million dollars to build so much loop and you go out and sell bonds and you take the money. If you didn't borrow the money, you can't do it. You can't say that is commingled with equity, and you don't know what paid for it, equity or debt.

Q. You can't say that? A. You can trace some and some you can't trace. All I am saying is you can't make a blanket statement either way.

Q. I again refer to a table which was attached to Dr. Shaffner's testimony, and it is on page 503 of the transcript. It shows that the average pipeline if it received area rates which included an overall rate of return of 12 percent, which is at least suggested, more than suggested, allowed in Permian, that that average pipeline would earn an allowance on equity for its production plant of some 28.46 percent.

Again coming back to the question I think you have partially answered at least, do you feel in your Pipeline

[3132]

Production Group that you should get a return on equity of that character which would, say, be in effect so far as parity is concerned with your independent producers or is your only interest price? A. First, I haven't seen the exhibit. I can't believe he is correct. I believe he has taken figures out of context, and I believe I can put figures together that will show a completely different answer by picking other companies.

Q. I won't belabor the question if you have not seen the exhibit. A. I think there are very few producing companies, pipeline or otherwise, that are making a 28 percent return on equity.

MR. LEITHEAD: In addition, I wonder if the question was confined to production operations or the overall operations?

MR. STANSFIELD: I intended it only to apply to production operations.

THE WITNESS: I just don't know enough about what Dr. Shaffner testified to.

BY MR. STANSFIELD:

Q. Mr. Elmer, again I think it is your testimony that there is no significant differences in the operation of the production end between pipelines and independents, is this not correct? A. That is correct.

[3133]

Q. Do you not recognize any differences in the costs of new gas possibility between pipelines and independents? A. What do you mean cost of new gas?

Q. I really refer to the Exhibit 36 of Mr. Jones which, if I understand correctly what he did, he compared or he came up with a study which he called "Current costs of new non-associated gas for pipeline production and comparison with all producers' current costs of new non-associated gas," and if I read his study correctly there are significant differences between his study and the similar study–I guess

[3133]

more than study–Commission determination of what would be a correct computation for this in Permian at page 192.
A. May I say this, when we run a production operation or you run one, you say I am going to sell my product for this, and your cost isn't going to be based on some composite that comes in through an exhibit in a Federal Power Commission hearing. You are just going to get out and do the best you can to make as much as you can under that. This is the historical records of what has happened in the past, and this is one of the things that is bothering all of us on this. We are all so used to in pipeline operations, in electric operations also, you are so used to being able to trend back costs, and you can't do this here. I am not saying that these figures are not correct. I am just saying we are looking at getting an even shake on the same principles in the future.

[3134]

Q. Let me make myself clear. I am not saying that these figures are incorrect. I am simply pointing out that there is a substantial, to me, difference between the figures that Mr. Jones has in his study, which is Exhibit 36, and a similar table that is included in page 192 of the Permian decision, which is 34 FPC 192.

MR. SHIBLEY: Could I interrupt just one moment, Mr. Stansfield. I am sure you recognize that Mr. Elmer has not been involved in the cost exhibits, but just for purposes of the record, are you asking as to the overall result in which Mr. Jones' study showed that using the Commission's formula or as he employed the Commission's formula new gas would cost 17-1/3 cents as against 16-1/2 cents or are you talking about those individual components being different in the end result?

MR. STANSFIELD: I am talking about the latter very definitely; to me there are differences in these components, and, therefore, those differences to me al least probably justify some difference by the Commission in regulatory treatment.

MR. SHIBLEY: But if they had looked at any group of any 15 independent producers, they probably would have had just as much difference among them as the whole.

MR. STANSFIELD: This could be true, but this isn't quite the problem we are talking about at the present.

MR. SHIBLEY: I am sorry. I was just trying to clarify.

[3135]

BY MR. STANSFIELD:

Q. Again all I am trying to ask, Mr. Elmer, to me there are differences, and I am not saying they are correct or incorrect at this time, but if there are differences, do not those differences justify some different regulatory treatment between pipeline producers and independent producers? A. My answer is I have been in the producing business for 15 years, and to me there are no differences. If you say there are and put a witness on, we would be awfully happy to cross-examine him.

Q. Turning to transcript page 716, again about two-thirds down that page, the second sentence of your answer, you state that "The production department or subsidiary can"– and I emphasize your word "can"–finance the same as independents." Is this actually done in general practice by a production department of a pipeline? Can you give me an example of it? I am talking about a production department. A. I really can't, sir. Lee me say this; There is no reason a company that has the department itself, that has the production all tied up in it, it is not separate, there is no reason that it can't sell a production payment, long-term or short-term, just as any independent. I can't give you a specific example of a company that only has a department doing this, no, sir, I can't.

Q. To your knowledge, it is not done very extensively

[3136]

by companies? A. I really can't say this. It is done very extensively by affiliates, yes.

Q. Now, at the top of page 717, and the statement there, "As a general rule neither the pipeline affiliates nor the independent producer has any material amount of long-term debt based on its producing properties." This again is true, as you say, of the pipeline affiliate as distinguished from a pipeline producer which has its own producing department? A. Yes, because you don't sell to that many departments.

Q. Going on to the bottom of that page, and particularly under Item B at the bottom, and this to me is a clarifying question, your testimony is that some of the basic advantages are, and skipping to "B" "When unused capacity develops in portions of the gathering and transmission systems, the pipeline producer or affiliated producer can intensify its efforts to develop production from geographic areas which will relieve this condition."

What do you envisage that would cause this condition, namely, the unused gathering or transmission capacity? I have a little difficulty there. A. I gave an example this morning on the Carthage field. In the late forties Southern Natural , Tennessee, United Gas, Texas Gas and Arkansas Louisiana all built pipelines in the Carthage field because then it was the biggest single field

[3137]

that had been discovered and everything went along great. All of a sudden, the field began to play out, and there just wasn't enough gas to go around. It is going down every year. So, there was an example. Two of the companies, or three, started looking around to see even for little things that they might find in that area. This is not a great big reason. It is a plus. It is a plus that we have used. If you have a production department, if you have a production subsidiary, and you have got a pipeline sitting there and they can do something in that area, it is beneficial to you, it is beneficial to your customers if they can do it.

Q. But it would be a fact, would it not, if you had unused gathering capacity, the chances of ever using that

would be rather nil, would it not? A. It depends what you call–

Q. If it is unused– A. If it is just a small gathering line. I am talking about branches of pipelines. Not all pipelines have one straight stretch.

Q. I am sure. A. So there may be some area of the line that went to a certain producing area that is becoming less useful and you try to do something with that.

Q. Mr. Elmer, would you care to express an opinion on whether a pipeline production company that has a producing

[3138]

department should look and develop production off-system? A. Oh, yes. You can't be in business just looking on-system. As I pointed out this morning, you are either in the business or you are not in the business, and you look for the best prospects that you can find. Generally, you won't forget your system. We, for example, have had somebody to walk in with a play that is in Utah, a couple of small ones, that we have taken. Basically I think you will find they are operating in the area they can connect to their piepline.

I think a very good example was a recent case here of Tennessee Gas Transmission that is going to build a major line into the Gulf of Mexico. People here from Tennessee can correct me, but a great deal of that gas was developed by them and found by them. They wouldn't have been able to do that if they had just been playing in one area. They had to run successfully their whole production company as we have to run ours. You don't limit it to an area. You play anywhere you can make money, because, as I pointed out, the funds that you get to drill the well next week have to come from the ones you generate this week.

Q. In my own mind I am making a distinction between your producing affiliate, which is a separate operating company to all intents and purposes similar to an independent

[3138]

producer, that is one situation, and the pipeline producer which has a department which is a production department. If I understand you

[3139]

correctly, you make no distinction between the two. A. It is hard not to make some distinction. The only distinction is corporate form almost, because what is part and what is not part? They operate the same. The departments are just as isolated as probably the divisions are. I know pipeline companies that have producing divisions and their offices are in a different city far removed from their pipeline operations, but for some reason they don't put them into a subsidiary. I, frankly, think it would be best if they did. That is because of our particular problem. Some other company might have a problem of another type that makes it impossible to have a subsidiary.

Q. Of course, we would both agree if this happened to be the way this ball would bounce and there was some advantage in being a separate affiliate that that is the way they would go as distinguished from a production department and affiliate? A. I think anyone would go the most advantageous route, yes, sir.

Q. I think you have answered this question at least in part before this morning, but I have a little difficulty in envisaging how the law of supply and demand will work under an area rate approach for both independent producers and pipeline production. Would you care to expand on that? A. It is hard for me to understand. Would you restate your question?

[3140]

Q. I think you have said on page 20, in answer to the question "Would the cost of gas to the consumer be increased if pipeline producers are accorded the same treatment as individual producers," and your answer is "no, and then "In the first place, over the long pull the price of

gas in the field will reflect quantities available in relation to demand."

Now, I am coming to the question if you have, and you are under area rate approach, and you have both the independents and you have your pipeline producers and their affiliates, just how does this law of demand and supply when you have got a price that is set for everybody ever come into being? A. What I am saying, I am saying that all prices of all products are fixed by supply and demand, that those that are fixed by a regulatory agency or a Government group, that the price they fix will have to follow the supply and demand route, and it will follow it for a while, and if it becomes out of kilter with the supply and demand price that would be fixed, that price is going to be changed.

Q. The area price is going to be changed? A. Or any price that is fixed by anything other than the normal working of the common economic cycle.

MR. STANSFIELD: That is all the questions I have.

BY MR. WHEATLEY:

Q. Mr. Elmer, when was Texas Gas Exploration Company organized?

[3141]

A. 1951 they tell me.

Q. When did it begin operations? A. That year right after that.

Q. Has that company had a consistent annual growth in its gross investment in producing leases, well equipment, and in intangible drilling cost? A. I think generally speaking; yes, sir.

Q. Why was it set up as a separate corporation? What factors were behind that? A. I believe that we felt we would like to start a production company and see what we could do with it. You are asking me about something that happened 15 years ago. We felt generally we would set up a small production operation. Some other companies

had already done it. Texas Eastern was in the business. Tennessee was in the business, Mississippi River Fuel was in the business. We said give it a go and see what we can do in the production business.

Q. Why did you set Texas Gas Exploration Company up as a separate corporation instead of proceeding in the exploration business with a division of your pipeline company? A. Because our people felt, and feel today, and for this reason we keep them completely separate today–I happen to be chairman of the board of the Exploration Company, but we have no other common employees–that it is easier–this may not be true in other parts of the country–it is easier for our gas

[3142]

supply people, that is, the gas supply people of Texas Gas Transmission, to work with the independent producer on new discoveries and to get information from them when there is a discovery well, and get logs quick and get a good look by their not having another department of the company in the same office that is in the same competing business with the independent producer. We have always had a rule that there is never information that passes back and forth between the two. For this reason our gas supply people get all this information from the producer. They advised us of that when we started. If you are going to have it, get it in a separate company, keep it away from transmission, otherwise there will be some trouble in buying gas. That is the basis we set it up and put it in a different city. We started the office at that time in Houston when our gas supply office was in Shreveport.

Q. Did tax considerations have any bearing on that? A. No, none.

Q. Did the treatment of tax costs in regulation have any bearing on the decision? A. No, none at all. I just told you what the reason was, and it is the same reason today.

Q. Did the fact that there is no requirement for accounting under a uniform system of accounts–that had no bearing on it, either. A. No. All that would have taken would have been a clerk

[3143]

half time.

Q. If production, however, is undertaken by an affiliate it is true, is it not, that any excess tax deductions that are generated can be applied more easily to offset taxable income of other nonjurisdictional affiliates than if the production is undertaken by the pipeline company itself?

MR. SHIBLEY: I object to that.

MR. LEITHEAD: I would join in that objection, Your Honor.

PRESIDING EXAMINER: The objection is sustained.

BY MR. WHEATLEY:

Q. Does Texas Gas Exploration make sales to its parent? A. Yes, sir.

Q. And to others? A. Yes, sir.

Q. What percentage of production is to Texas Gas Transmission Company? A. I would say between–of gas? You see, we produce oil also.

Q. Of gas? A. Of gas, between 60 and 70.

Q. And the balance is sold to others? A. To others, that have pipelines nearer than Texas Gas.

Q. In setting up contracts between your pipeline and its affiliate, Texas Gas Exploration Company, did you take the position that the affiliate was out of the reach of the Federal Power

[3144]

Commission's jurisdiction? A. Oh, no, sir. We have set these contracts up, we have filed these contracts, these contracts have been exhibits in our rate proceedings of the pipeline company. The Staff of the Commission has looked at the contracts. They have had field checks on the com-

pany. No, they are jurisdictional contracts. We recognize that they are jurisdcitional contracts, and always have, because we didn't enter into any–I guess we had one before 1954, but that was amended after the Phillips decision. There is no problem on this.

Q. As far as the jurisdiction of the FPC is concerned, you treat your affiliate as though it were in effect a production department? A. No, we don't. I don't know why you are tyring to bring me back into the production department. It is a subsidiary. It is a hundred percent owned subsidiary of our company. It has been in business for several years. It has built up surplus. It borrows its own money. It does its own financing. It has its own officers. It is a separate company. It is not a department, and it doesn't work anything like a department. It is in a different city.

Q. Referring you to transcript 708, the middle of that page, you state the Pipeline Production Group's position in this proceeding. What is the difference between paragraph 1 and paragraph 2?

[3145]

A. I don't think there is any. I think two just amplifies one.

Q. I think you were referred to the clause in the last part of paragraph 2, the "but" clause, and I believe you stated that if the area rate is in excess of the contract price then the contract price would govern? A. That is correct.

Q. Is this the contract price between the affiliates? A. That is right.

Q. Is paragraph 2 talking about on-system sales only? A. That is all I am talking about. In other words, we assume from Commission decisions, and so forth, we certainly operate that way, that the only place there is any question is on-system sales.

Q. Assume that there is a pipeline company and an affiliate producer and assume further that the pipeline com-

pany has its own production and supplies part of its gas requirements from that source, that the pipeline company also purchases part of its supplies from the affiliated producer, and also purchases part of its supply from a non-affiliated producer. Assume an area price is established which is in excess of the contract price between the pipeline company and its affiliated producer– A. We have got to keep in mind, Mr. Wheatley, that we are talking just about the future here; right?

Q. Yes, the future–

[3146]

A. We are not talking about existing contracts?

Q. No, we are talking about a future contract.

Assume that an area price is established which is in excess of a contract price between that pipeline company and its affiliated producer but is less than the contract price between the pipeline company and the non-affiliated producers, under these circumstances– A. I guess I am not listening. Would you mind saying it once more?

MR. SHIBLEY: May the reporter read it back?

(Question read.)

BY MR. WHEATLEY:

Q. Under these circumstances, is it the Pipeline Group's position that the affiliated contract price would be the price at which the affiliated production would be sold to the pipeline and the non-affiliated production would be sold to the pipeline at the area rate? A. If so ordered by the Federal Power Commission. In other words, we take the position that we pay the contract price to the nonaffiliated producer unless the nonaffiliated producer is ordered by the Commission in your example to decrease his price to the area rate.

Q. Under the example I gave you, at what price would the pipeline company purchase its own production, price its own production?

[3147]

A. I don't understand.

MR. SHIBLEY: Let's get this example straight now before we get confused. Isn't the question simply you are asking if the area rate is fixed at a level that is above the contract price between a pipeline and its affiliate, what price does the pipeline pay its affiliate, the contract price–

MR. WHEATLEY: Oh, no, the pipeline also has production from its own production which it will have to price. Now, the question is at what price under the pipeline Production Group's theory would this production from its own pipeline department be priced?

MR. SHIBLEY: Isn't the question–let me restate it to make sure we have it.

Isn't the question now, if the Commission fixes an area price at what price would the pipeline department's production be treated; isn't it jsut that simple a question?

MR. WHEATLEY: You have the further factual assumption included of a pipeline company having a contract with its affiliate producer at a price below the area rate.

THE WITNESS: I think you are just asking this. It doesn't make any difference who you are selling to if you have contracts, but what you are saying is, what happens if you don't have a contract? This is what you are trying to say, is it not?

MR. WHEATLEY: No. You have stated that the contract price would control where it is less than the area ceiling. I am just

[3148]

asking you a case where the pipeline company has a contract price that is less than the area ceiling to its affiliate, then now does it price its production from its own department? A. First, let me say this, Mr. Wheatley, I don't know very many pipelines that are producing both through departments and divisions.

Q. We are talking about the future now. A. They aren't going to do it in the future. I think you are over-complicating what you are trying to say here. All I can see is, if you don't have a contract, if you are working through your department, how do you price your gas; isn't that what you are really trying to say?

Q. I am just trying to understand what the recommendation of the Pipeline Production Group is and how it is going to work out in these various possibilities. A. If that is your question–

Q. My question goes back to the hypothetical circumstances.

MR. SHIBLEY: Mr. Examiner, in all due deference, I know that Mr. Wheatley has a question there, and it is a long question, but as the witness has pointed out, and as I tried to do in a very polite and gentlemen way, in order to answer Mr. Wheatley's question, he is just complicating it by saying assume that it also has an affiliate. Mr. Elmer has answered the question as to affiliate. There cannot be any doubt as to what our

[3149]

group recommendation is when an area price is fixed as to what happens to a sale to an affiliate. That leaves the question as to what happens when there is a sale to a pipeline production department. Mr. Elmer has tried to answer that. Mr. Wheatley is trying to bring him back to this lengthy series of assumptions. Mr. Elmer would undertake to answer what the result would be under our recommendation, but I submit he ought to have a question that would be meaningfully put to him.

MR. DIETRICH: Might I try to indicate what I think the record says?

Mr. Wheatley has hypothesized a situation whereby a pipeline gets gas from three sources, independent producers, from a wholly-owned affiliate, or an affiliate; and, third, from its own producing department. Say hypothe-

tically that the area rate is 16.5 cents. It is currently buying gas from its affiliate at 14 cents. In that situation how would the pipeline price gas from its own producing pipeline.

Is that right, Mr. Wheatley?

MR. WHEATLEY: That is it exactly.

MR. BROWN: Of course you are assuming that the gas is all produced from the same area?

MR. DIETRICH: Mr. Wheatley I assume is talking about an area in which an area rate has been fixed; so we have an area rate of 16.5 cents.

THE WITNESS: I think this is what is going to have to

[3150]

answer that?

MR. DIETRICH: I think that can be answered.

THE WITNESS: I think this is what is going to have to happen, Mr. Wheatley.

First, as I pointed out, the bulk of the company production will be through affiliates or subsidiaries, one. Now, let's talk about that that isn't, and that is what you are talking about. I think if the Commission decides, which I hope they will, that we get parity of treatment with the independent producer for department gas that a procedure, and a standard procedure– I think we discussed this same question this morning–will have to be worked out where in effect in conjunction with hooking that gas up to the system that company will have to file some kind of a document with the Federal Power Commission which in effect would be almost the same as a contract with itself. In other words, it spells all the terms out as to price.

BY MR. WHEATLEY:

Q. What will the price be in the document that is filed, 14 cents or 16 cents? A. It would be 16 cents in your case because that gas would now be–wait a minute, that gas is being connected when the price is 16 cents. The reason that the gas in the contract is 14 cents and not the 16.5 is that that was connected back when the price was 14 cents.

[3151]

Q. You are changing the facts of my hypothesis. We are talking about the same time.

MR. SHIBLEY: It is Mr. Dietrich's.

MR. DIETRICH: He agreed it was his.

THE WITNESS: First of all, the pipeline is going to have to price its gas, Mr. Wheatley. The pipeline can't price its gas to itself on a minor advantageous basis than it can to an independent producer.

BY MR. WHEATLEY:

Q. It can price the gas– A. It can price it lower. You are asking me what a pipeline would do. You would have to ask every pipeline that question at the time it came up. I don't think you can get any general philosophy. Normally, you are going to charge the area price. That is what we are asking for. If we wanted less than the area price, we would be here asking for it. But normally that pipeline is going to charge the area price in effect for its gas, whether it be from a subsidiary or whether it be from its department.

MR. LEITHEAD: If the quality of the gas was such that it reduced the price down to 13 cents–

THE WITNESS: Then they would have to reduce it accordingly.

BY MR. WHEATLEY:

Q. Mr. Elmer, referring you to transcript 708, in paragraph 3, beginning at the bottom, what does "Standards,"

[3152]

"principles," and "criteria," as you use the phrase, refer to? A. I think one example was just cited here: Quality, for example, when the Commission fixes an area price, if they tie that to certain standards, and so forth, then we would be entitled to the same thing.

Q. I have been somewhat puzzled by the precise meaning of paragraph 3. Would you agree that this is a correct statement as I have rephrased it: "Further applying the

[3152]

same standards, principles, and criteria in regulating such production as are applied from time to time in the regulation of jurisdiction sales of gas by other producers, except where particular circumstances warrant a different treatment"? A. I would have to look at what you read. It sounds the same to me.

MR. SHIBLEY: It sounded similar. Was this a syntax problem, Mr. Wheatley?

Is there a difference between what you have said and what is in here?

MR. WHEATLEY: That is what I am trying to find out, Mr. Shibley.

BY MR. WHEATLEY:

Q. Actually, what I really want to know, Mr. Elmer, is what exception do you have in mind which you say are "warranted by particular circumstances"? A. There may be a possibility that the Commission may,

[3153]

for example, exclude certain areas from the area price approach of regulation. I don't know. That is what we had in mind. There has been a lot of talk back and forth, for example, about Appalachia. Well, how should Appala-

BY MR. WHEATLEY:

Q. Assume a high cost producer which its management says desperately needs the gas, in your opinion are they going to get a different treatment? Do they come within the exception that you have referred to here?

MR. DIETRICH: For clarification, when you say a high cost producer, you mean a high cost pipeline producer?

[3154]

MR. WHEATLEY: Pipeline producer.

MR. SHIBLEY: I think I will object, even as helpfully clarified, Your Honor. It is the savings clause. We can't define it any more clearly than this. The Commission

hasn't defined it any more clearly than this. I appreciate Mr. Wheatley's question being asked, but I think Mr. Elmer has said whatever the savings clause means for the independent producers we shouldn't be excluded and we shouldn't have any special advantage.

Isn't that what it amounts to, Mr. Elmer?

THE WITNESS: We are not asking for an exclusion. We don't mean that this clause should differentiate between the independent producer and the pipeline producer.

BY MR. WHEATLEY:

Q. You mean you don't envision a case where a pipeline company, per se, would have certain special circumstances that it would want to rely on which, of course, no independent producer—the situations wouldn't be comparable at all?

MR. SHIBLEY: Are you talking about envisioning it or recommending it?

MR. WHEATLEY: I am asking if he envisions that this exception could cover such a pipeline company?

THE WITNESS: We are leaving this up to the Federal Power Commission. The Federal Power Commission regulates the pipeline producer. In effect, as Mr. Shibley pointed out, we just

[3155]

put the clause in. If there is something that is an exception, let the Commission take care of it.

PRESIDING EXAMINER: Did you put in the clause or did one of your associates advise you to put it in?

THE WITNESS: This paragraph right here, the answer to "What is the basic position of Phase I?" was prepared jointly by every one of the 13 companies, and my whole testimony is based around this paragraph.

BY MR. WHEATLEY:

Q. Is it your position, then, that the area rate which you propose for pipeline producers is the highest possible rate that any such producer could seek to obtain?

[3155]

MR. SHIBLEY: What does that mean? Based on his answer to the last question?

MR. WHEATLEY: I am just asking whether he envisions a case where an individual pipeline company might seek to obtain a higher rate than the area rate which is supposed to be set or to obtain in this docket.

MR. SHIBLEY: I submit this is really the same question he asked before. Mr. Elmer just answered it. I suspect there is a list over there, and they didn't anticipate the answer or something—I can't see the difference—though I don't know that.

MR. WHEATLEY: This one wasn't on my list, Mr. Shibley.

MR. SHIBLEY: Maybe you had better stick to your list.

[3156]

I am sorry, if it is a different question. I don't really object to it, but I think it is the same question.

PRESIDING EXAMINER: Mr. Elmer, do you envision any exception? Do you follow the question?

THE WITNESS: I don't think there is any rule or regulation covering as large an industry as this that the Federal Power Commission won't find by their own volition or otherwise down the road somewhere they think there might be exceptions to something.

I am not going to sit here and say there shouldn't be any. I don't know. This is done by the Federal Power Commission. I am saying that we in the group I represent are just asking for one thing. We are asking for whatever the treatment is that is given to an independent producer for its gas that we be given equal treatment. If there is maybe some pipeline that isn't in this group, or if there is some pipeline in Alaska or Hawaii or somewhere else that has got a problem and they come to the Federal Power Commission and the Federal Power Commission may very likely say there should be an exception, and that is their responsibility to determine it.

I can't answer the question.

PRESIDING EXAMINER: I think the spirit of your answer is that exceptions are always possible to the regulatory scheme.

THE WITNESS: That is correct.

PRESIDING EXAMINER: Mr. Wheatley evidently wants to know

[3157]

whether they are probable, whether you see them in the horizon.

THE WITNESS: Our group that I represent sees none.

BY MR. WHEATLEY:

Q. Does that mean within your group or within the pipeline industry as a whole? A. I am only testifying for 14 companies.

Q. And you are just testifying for those 14 companies? A. That is correct. That is all I represent.

Q. Do you think or do you have any opinion as to whether the Commission should consider any different rule with respect to the other companies? A. I really don't know. Let's just take the example I gave, and maybe you or Mr. Smith are familiar with it. I am not.

Take Appalachia. I don't know what the problem is in Appalachia. I am not familiar with it. I know there has been some discussion as to how Appalachia will work.

Q. Dont't you think this might be a very crucial consideration in determining whether or not the Commission should make its regulatory method?

MR. SHIPLEY: I object to that question.

PRESIDING EXAMINER: The objection is sustained.

BY MR. WHEATLEY:

Q. At transcript 709, in the first question that is asked of you there, what did you understand the phrase "special

[3157]

BY MR. WHEATLEY:

[3159]

Q. What does the phrase "through full participation of the entire producing industry" mean? It is the end of the second sentence. A. All I am trying to say is let's put the entire producing industry together, treat us all the same; the pipeline, the affiliate producers, the independent producers.

Q. You are not referring to the industry as it is presently constituted, are you? A. As I pointed out in answer to some questions this morning, I think it is important that the whole industry participate in drilling as many wells as possible, going back to my prepared testimony, "which will insure adequacy of gas supplies at reasonable prices."

Q. From this morning's testimony, I take it you are interested in bring in some new producers? A. Yes, sir. If you have got some spare money, we have got a place for you.

I am serious. We need all we can get.

Q. You don't get spare money when you are on the public side, Mr. Elmer.

Referring you, Mr. Elmer, to transcript 710, your answer near the bottom of the page where you refer to the risks being taken are of exactly the same magnitude. Specifically what risks are you talking about there? A. If you followed my explanation this morning of what

[3160]

we went through in the off-shore area, just what we were going to get for the money we spent. What is down there? That is the risk.

Q. You are talking actually about the risk of finding gas, aren't you? A. I am talking about the risk in the finding of a petroleum product, of getting a financial return out of the money put into the leases, the geophysical work, the geological and the drilling, what am I going to get back.

Q. You are talking both about finding and selling the gas; the risks are the same? A. There is no difficulty in selling it. The risk I am talking about is finding it. That is the risk we talk about. The risk of finding.

Q. It is limited, then, to just finding, is that right? A. That is what I am basically talking about.

Let me say this: Finding an amount that is saleable. In other words, sometimes you find gas that you wish you hadn't found because it is so little, but finding a marketable amount.

Q. You are not then comparing the risks of selling the gas between a pipeline producer and an independent producer? A. I tell you there is no risk in selling gas today. There are ten buyers for every seller.

Q. Isn't it true that certain types of companies would have less risk in selling the gas than others?

[3161]

A. There is no risk in selling the gas. When you have got one apple and ten people are hungry, there is no risk.

Q. As to markets, it is true, is it not, that the pipeline producer has an insured market for his gas? A. I have answered you three times in a row, the same question. You are trying to ask me a question on something that isn't true. I have pointed out there is more of a demand than there is a supply. All the projections that are made show there is more demand than there is supply. And now you are trying to say, well, don't you have an advantage in selling? You don't need an advantage in selling. Everybody wants your gas. It is who you sell it to.

* * *

[3163]

Q. Mr. Elmer, is it your position that the risk to the investors of a pipeline producer under cost of service regulation is the same in exploration activities as the risk to the investors of an independent producer under area rates? A.

[3163]

I feel that the cost of service approach, Mr. Wheatley, of trying to regulate a producer and trying to find an equitable method of allocating between oil and gas is so complicated you just can't do it. I don't know how you compare the risks. I think the risk, per dollar spent, if you spend ten dollars or ten million dollars, you as an independent producer, me as a pipeline fellow, I think our risks are the same assuming we both have the same talent. You are saying what are the risks to our stockholders if you are on an area price and I am on a cost of service. I say because I don't think the cost of service think can work that I think the risk is greater to my stockholders solely because of the unworkability of the cost of service theory for production.

This has nothing to do with the risk of finding the gas which is the same per dollar spent, but for getting the dollar back to the stockholder, I will put my money in the company that is on the area price basis versus the one on the cost of service basis.

Q. If you had two companies that both went into production at the same time and one was on cost of service and they both came up with nothing but dry holes, the one on cost of service

[3164]

would be in a much better position, would it not, than the other? A. Where are they going to get their money?

Q. Assuming the stockholders put up the funds to start the operation off. A. I am not assuming that any business that is a failure is a successful business. I am assuming that the talent that we have in industry is going to make all business succeed of this nature, and I can't look at it that way. To answer your question, I think that the stockholder taking into account the history of cost of service regulation of the producers, the history of statements that are made by this Commission, particularly in the Phillips case, where they said it can't work, it is unreasonable, it is unworkable, it is no good. I mean I have got it here, I will read it, I

don't have to as you are familiar with it. Then you are saying to me does a stockholder take more of a risk going into one regulatory treatment that the regulatory agency agrees to versus one which the regulatory agency itself says doesn't work.

Q. The Federal Power Commission has never said that cost of service doesn't work for pipeline companies that go into the producing business.

I am just asking you to compare the risk to that kind of company. A. I am reading from Phillips Opinion 338, September

[3165]

1960, page 5: "Producers of natural gas can not by any stretch of the imagination by properly classified as traditional public utilities. The experience of the Commission in this case as well as in many other producer rate cases during the last five years has shown beyond a doubt that the traditional original cost," and so forth, "is not sensible or even a workable method of fixing the rates for independent producers of natural gas," and we are saying we are the same as an independent producer.

I think I have answered your question. I have tried to.

Q. This morning you referred to two pipeline companies which you stated withdrew from the producing business and you also referred to two companies which you stated had made no effort to go into the producing business, although they had expressed an interest in doing so. A. Little or no effort. I think Florida has made a very minor effort.

Q. How did the two companies that you stated withdrew from the production business accomplish this? A. I don't know. I think they both sold their production operations to other parties, both I believe to major oil companies.

Q. Didn't they sell them to wholly-owned subsidiaries first? A. No, they were subsidiaries. What do you mean selling

[3166]

them to subsidiaries?

Q. Northern Natural Gas Company. A. They were subsidiaries. You don't sell to a subsidiary, it is the subsidiary.

Q. Aren't you familiar with the fact that Northern Natural Gas Company spun off their pipeline production division to a wholly-owned subsidiary subsequently–

MR. SHIBLEY: I object.

PRESIDING EXAMINER: The objection is sustained. It is argumentative, and this witness doesn't have to testify to that.

BY MR. WHEATLEY:

Q. Do you know when these two pipeline companies withdrew? A. Not exactly, no. In the last five years.

Q. Within the last five year? A. I would say so, yes, within the last five years.

Q. Do you know when they went into production originally? A. No, not specifically. They were both in for a long time.

Q. Do you know where they were in production? A. Generally, in the Hugoton-Anadarko area basically. That is where the bulk of the two companies' production was, I believe.

Q. Do you know what reserves they had? A. No, sir.

MR. SHIBLEY: I am going to object, Mr. Examiner, to this

[3167]

whole line of questioning. We are trying to be reasonable here, but really Mr. Elmer is not presented to this forum to give some kind of a historical chronicle of these companies.

MR. WHEATLEY: The witness has used this in his testimony, and we want to get to the basic facts underlying his testimony.

PRESIDING EXAMINER: He answered your question, Mr. Wheatley. He said he didn't know.

BY MR. WHEATLEY:

Q. Did they give a reason for their withdrawal? A. Not to me.

Q. At transcript page 711, on what evidence that you have presented do you rely for the conviction you express that the level of exploratory drilling and production activities by pipeline owned and controlled producing organizations would have been higher if they had been assured that the rate treatment of pipeline produced gas would be the same as that which an independent producer would receive? A. I have spent the last five years working on this subject here, almost five years, since early in 1963, and in connection with that I have worked with the key people in every one of these companies that we have got on here, we have discussed this many times, and from listening to these people in duscussing these problems I am absolutely convinced that this statement is correct.

Q. What period of time are you talking about, just the

[3168]

last five years?

MR. SHIBLEY: Are you asking him during what period of time would they have participated more in production activities?

MR. WHEATLEY: Yes, he states "I am convinced there has been less exploratory drilling and production opportunities" beginning at line 13 on page 711.

THE WITNESS: I would like to keep it to just the recent years for this reason. I think we are getting into something–and let's just answer your question yes, for the last five years and if I go any farther, I am getting into Phase II of this proceeding, and I don't want to get into Phase II of the proceeding.

BY MR. WHEATLEY:

Q. Mr. Elmer, in stating that you were convinced that there has been less exploratory drilling than would have taken place had the regulatory treatment been the same as the independent producers', is it not true that the regula-

tory treatment for independent producers was not known for the first time until the Permian case on August 5, 1965? A. No, that is not correct. I feel going back to this decision that I just read, that starting at that date, September 28, 1960, that that opinion wrote the end to a cost of service approach for the independent producer.

Q. Did it mean an average field price? Strike that. Did it mean an average cost for producers on an area

[3169]

basis? A. Average cost? I didn't say that. I said they could quit worrying about an unworkable cost of service formula, which is what it meant. We still haven't gotten to the final answer.

Q. There was no indication of what the final answer would even be until the Permian decision, was there? A. You don't understand what I am trying to say. They got rid of the cost of service shackle, and we hadn't. I am saying had this opinion also said it is the end of it as far as company-owned production is concerned, then I think there would have been more drilling in that five-year period.

Q. In the last line of page 711 of the transcript through line 4 of page 712, is this an article of faith or is it based on proof? A. I have no proof, no more than I have any proof when I answered your first question and said it was just on the basis of my experience working on this thing for five years. I work with these people. I talk to them. They are becoming discouraged.

We wrote a letter to the Chairman of the Federal Power Commission in September of 1963 asking him to please give us some guidelines, and we don't have them yet, and it is just lack of enthusiasm about this whole production matter because they don't have any guidelines. All I am saying here is if we don't

[3170]

resolve it here, I just believe it is going to have a detrimental effect on the rate of growing by the pipeline producer.

Q. Is it your testimony that pipeline producers do not have the years of experience of personnel that the much larger companies among the independent producers? A. No. Where are talking?

Q. I refer you to transcript 712, line 17. A. No. What I am saying is that if you are going into the business, it takes years, as I think we talked this morning–someone said eight years, which I certainly agree with; it may take longer–to build up a staff, to build up records, to build up your maps That alone, your area maps, you develop these yourself, and it is a tremendous problem. I am saying in going into the business you have to compete against what these larger organizations are doing. To stay in the business, you have got to have adequate personnel to do the same job.

Q. For quite a number of the pipeline companies, clearly they would not have that type– A. What?

Q. I say for quite a number of the pipeline companies they clearly would not have that personnel and experience that you have referred to as presently exists among the independent producers?

MR. SHIBLEY: Producing companies? Are you asking about

[3171]

producing companies?

MR. WHEATLEY: He says, "A pipeline company either going into the business, or attempting to stay in the business, must compete against years of experience of personnel of much larger companies among the independent producers."

THE WITNESS: The only pipeline companies that don't have that personnel that I know about are the two that are not in the business. Just because you are not big in number doesn't mean you are not good in quality. I am sure

[3171]

that all the pipelines who are in it have got some capable people. I have met some very capable ones.

Q. Is it the Pipeline Production Group's position that it should have the same rate treatment accorded independent producers even if such treatment while satisfactory for independent producer production is not satisfactory for pipeline production?

MR. SHIBLEY: I object, Your Honor.

PRESIDING EXAMINER: The objection is sustained. It is an argumentative question.

BY MR. WHEATLEY:

Q. Referring you to page 712, the last answer on the page, are you talking about a pipeline company going into the business of searching for and producing gas and oil in competition with independent producers for the purpose of producing gas for their own needs and for the purpose of selling

[3172]

gas and oil in competition with independent producers to others? A. As I have pointed out several times, Mr. Wheatley, you can't go into the production business solely to produce gas for your own needs. It isn't a factory. It isn't something where you can pick a location and build a plant. You go into the production business and you try to generate enough cash and earnings to keep it going, and you go into the overall production business searching for your oil and gas. You can, and pipelines and we do, concentrate your lease buying programs to the extent possible in the general areas that you might get to buy your pipeline if you get a large enough reserve to justify going to get it, but you can't pull it out of context and say you can go into this business or that business.

Q. I take it the answer is yes?

MR. SHIBLEY: I object.

MR. WHEATLEY: Did you rule, Your Honor?

PRESIDING EXAMINER: No, I didn't. He gave you an answer.

THE WITNESS: He asked me a question, and I gave him an answer, and he said I told him something elso. I don't know.

MR. SHIBLEY: That is why I objected.

BY MR. WHEATLEY:

Q. Referring you to the transcript at page 713 at the top, near the top of the page–actually, I think it starts on the bottom of page 712, you say without a parity of rate

[3173]

treatment, you do not see how any pipeline management can be expected to continue investing in production operations.

Isn't it the fact that not all pipeline managements engaged in production are arguing for the same rate treatment as may be accorded independent producers? A. It is my understanding that there may be one or two that feel differently than our group. Let me say, though, that I think in those specific cases I am not sure that the independent producer is also satisfied with the treatment they are getting.

Q. On page 713 you attribute risk of disallowance of cost improvidently incurred as limited to regulation on the individual cost of service approach.

Isn't there a greater risk of not recovering costs on an area rate basis fixed on an average nationwide cost? A. You know what you are going to get for your product there. On an area price basis you know what you are going to get for your product, and you run your business and you try tomake a profit, whereas if you can't make one, you finally sell out. But in a cost of service, you don't know what you are going to get. I just refer you to the Staff's position in the Mississippi River Fuel case, RP63-2, August 20, 1963, and the Examiner's decision. This is the one that scared the whole industry to death, when in effect they said all of the dry holes you drilled except those for produced wells were off-

[3174]

system, and you don't know when you go in what you are going to get retroactively. But in an area price you know what the rules are, and you play the game or you don't play it. We didn't know the rules on this one.

Q. Is it your statement that the Examiner upheld the Staff? A. He did not, I don't believe. That is not the point. This case was settled. But the worry is there. I don't know what the position of the Commission will be. Staff counsel may have asked me this morning on prudency. It is easy to tell in running a pipeline to draw some kind of a line between a prudent cost and an imprudent cost. In production we don't know. Is it prudent to spend 20 million dollars for a lease? If you get a trillion feet of gas, it is very prudent. If you don't, somebody may say it wasn't. We don't know. It is this indicision that is bothering us. All we want to know is what are the rules.

Q. You also know under the area rate rule, do you not, that you have a 50 percent risk of not hitting the average nationwide cost? A. We think we have as good or better than the average nationwide talent, and we hope we have as good as the average nationwide luck, so we will run because we know what the price will be.

Q. You say "we." You are referring to whom?

[3175]

A. The pipeline producers that I represent.

Q. Your 14 pipeline producers? A. That is correct.

Q. Is it not true that whatever rate-making regulatory method may be involved, all costs are subject to disallowance for unreasonableness or being improvidently incurred?

MR. SHIBLEY: I object to this as an improvident question.

PRESIDING EXAMINER: The objection is sustained.

BY MR. WHEATLEY:

Q. Referring to your testimony at transcript 716, you said in your opinion the majority of these people believed— A. Where are we, sir?

Q. We are at lines 2 to 7.

You say that in your opinion "the majority of these people believe that a well-managed production department or subsidiary is an asset to the financial standing of the pipeline company." A. That is right, yes, sir.

Q. How would these people feel if the pipeline does not recover its high costs under an area rate ceiling? A. All I know is that there are several companies–I have several copies of releases of these companies if you would like to see them after the hearing–that look on a company that has a successful producing operation, as I explained this morning, and even up to the time it is producing they live in hope, as an asset to the stock from the standpoint of its

[3176]

equity value to the stockholder. Why they do it, I am not an analyst and I haven't asked them how they would feel under different conditions. I have Shield & Company, here is Merrill Lynch. I have several of them here, Value Line, all saying the same thing. You find these all the time.

[3177]

Q. Haven't they reached these conclusions in the context of– A. I don't know how they reached the conclusions. I am not an analyst. I am just telling you what they are putting out to the general public to read.

Q. They are putting this out to the general public to read based on the existing method of regulation before the Federal Power Commission, are they not? A. I want to read you one as long as you brought it up.

PRESIDING EXAMINER: Mr. Elmer, you explained this topic very well this morning, and I don't want to hear another debate on it.

THE WITNESS: Allright. Thank you.

BY MR. WHEATLEY:

Q. At transcript 716, in describing the financing of production operations, you refer to cash generated from the

sale of the product, borrowing money through oil payments or pledging production properties. All this presupposes, does it not, a successful drilling by the pipeline producers and the independent producers? A. Oh, yes, sir.

Q. Referring you to transcript 717, the question and your answer beginning on that page wherein you refer to advantages of a pipeline company having a production operation. I believe you have been asked some questions about this. Referring

[3178]

to Item B, if the unused capacity develops as a result of lack of markets you didn't assume that, did you? A. No, the unused capacity in the example I gave about Carthage developments–you see we are talking about supply. This is a supply problem. I am saying if you have unused capacity in a portion of your system to a supply area that becomes empty, then if you can do something to fill that up you get a lower unit cost on the line.

Q. Referring you to I guess it is Item (d) on page 718, does a production operation if unsuccessful from an earnings standpoint make it easier for the pipeline to compete with other industry for capital in the money market?

MR. SHIBLEY: I object, Your Honor, Indeed this is the same question asked about three minutes ago.

PRESIDING EXAMINER: The objection is sustained.

BY MR. WHEATLEY:

Q. At transcript page 720, lines 20 to 23, you refer to the fact that under area rates production from a particular field may cost a few cents more and in another case a few cents less under one system, namely, area rates, than the other system, which I presume refers to cost of service. You concede, do you not, that if the Commission should change to area rates from cost of service there will be some consumers in certain areas who would be paying more?

MR. SHIBLEY: Are you asking about Phase I?

[3179]

MR. WHEATLEY: Yes, Phase I.
THE WITNESS: No.
BY MR. WHEATLEY:

Q. If you assume the same continuation based on the past performance– A. We can't. This is what I am trying to say. What are we going to do in the future? This is what we want to know.

Q. What do you mean when you state in your testimony that apparently when you go to area rates it is possible that the output of a particular pipeline producer from a particular field will cost a few cents more? A. Where does this say this?

Q. That begins at line 20. A. Let's go back to what the question is, sir, that I am answering when you are taking this out of context here. The question was "Would the cost of gas to the consumer be increased if pipeline producers are accorded the same treatment as the individual producers?"

We point out basically that we feel we will have greater participation of the industry in developing more gas and more supplies and that will ease the pressure on the demands for pricing overall which should help them. You just can't say everything is going to be cheaper. We say it may affect one particular field a few cents more or a few cents less than it would be on a cost-of-service basis, but to the overall consumer that

[3180]

we are looking at, I feel this is the best way to go.

Q. On an overall basis? A. Yes. The Commission can't look out for just your gas bill or mine. They have to look out for everybody's.

Q. But you do concede there will be variances in different areas? A. Absolutely. If you could run a cost of service on every individual field, and have an area price for the independent producers, it is not going to come out to

[3180]

that level. There are going to be some higher and some lower.

Q. You have stated that in your opinion in general that you feel there is a need for an increased incentive to pipeline companies to engage in the exploration and production business beyond that provided by the present cost of service method, and that is the reason for your asking that pipeline producers be able to shift to area rate, increased incentive?

MR. SHIBLEY: Go ahead, but this is obviously starting off on the wrong foot.

BY MR. WHEATLEY:

Q. Is that your testimony? A. My testimony is, going back to those three items which sets out the whole thing, we think we should have parity treatment. If we sit in an area of indecision and don't know what the rules are, as we have sat in for the last five years, not knowing what will come out of the cost of service, unless we know

[3181]

where we are going, it will destroy the incentive. It has destroyed, it is destroyed, and is going to destroy incentive to drill.

Q. As I took your testimony, when you said you wanted increased incentive– A. You are trying to imply we want increased money. This is not what we are saying.

Q. All you want is clarity. A. We want clarity, and we want the same treatment that our competitors are getting, the same people we are competing with, not from the standpoint of outselling them or outbuying them. We are competing with them, taking the same risks and finding the same hydrocarbons that are down in the earth, and we want the same treatment, the increased incentives with some guidelines and this kind of a guideline.

Q. You said earlier this morning that the only type of incentive that really amounts to anything is an economic incentive?

MR. SHIBLEY: Mr. Examiner, I hesitate to object again,

but Mr. Wheatley is just sitting here disputing with the witness.

MR. WHEATLEY: Your Honor, ithis is–go ahead, Mr. Shibley, I am sorry.

MR. SHIBLEY: We covered the incentive question. I don't really believe it is obligatory on everybody just because they

[3182]

are not in complete sympathy with our recommendation to go through every aspect of the testimony, and that is all we are doing here.

PRESIDING EXAMINER: Mr. Wheatley, I think you are hoping that Mr. Elmer will change his approach, and I am going to let you try it for a little longer. I think you are running out of questions.

MR. WHEATLEY: You are right, this is my last question.

BY MR. WHEATLEY:

Q. I take it is your testimony, then, Mr. Elmer, that you don't think or believe that shifting to area rate provides any increased economic incentive in terms of extra money to the pipeline companies over what they would get under cost of service? A. It does this. One, it will give the pipeline producer a knowledge before he spends his money for all of the various phases of his operation how much per Mcf he can get for the gas he finds if he finds it, so when he sits down and goes through the gyrations like we discussed this morning, and tries to determine what he is going to bid for that off-shore lease, and how much he tells his partners he can put in, or he is going to drop out, he knows a figure that he can apply to so many cubic feet per hundred feet of sand and so many feet of sand, he knows this and he can run his business as a business. He isn't going to put something in and say, "Oh, my goodness, it didn't work out

[3183]

that way." He gets certainty.

No. 2. He gets more money if he is more successful than you might say the average producer. He gets less money if he is less successful than the average producer. He knows where he is going. He knows the guidelines he has to stay in, and he and his whole organization have the incentive to run a successful business within those guidelines.

[3184]

Q. When is he going to know whether his costs are going to be such that he can determine whether he can or cannot live within the area rate?

MR. FLETCHER: I object to that as argumentative.

MR. SHIBLEY: I object to that as nonintellectual.

PRESIDING EXAMINER: The objections are well taken, but I think Mr. Elmer is going to give him a short answer.

THE WITNESS: Every business gets an operating statement every month. You could ask this question of any business. If we went into the business of making cigars, pencils or glasses, it is the same thing.

MR. WHEATLEY: I think we have no further questions, Your Honor.

MR. SLYE: Your Honor, I only have a very few questions. I think I can finish this afternoon.

PRESIDING EXAMINER: You don't have to look at the clock. We will stay with you.

BY MR. SLYE:

Q. Mr. Elmer, I am Bill Slye. I represent Texaco. You have stated many times today and in your original prepared testimony that you believe pipeline production should receive parity of rate regulatory treatment with independent producers. Am I correct that you do not seek any advantage over independent producers in the regulatory method?
A. That is correct.

[3185]

Q. And your position is then that the pipeline production activity should be placed on an equal competitive basis with independent producers in the finding, developing and marketing of gas reserves, is that correct? A. That is correct.

Q. So you would want to compete in the acquisition of leases on an equal competitive footing with the independent producers, correct? A. Yes, sir.

Q. Compete in the exploration and development of gas reserves on an equal competitive footing with the independent producers? A. Yes, sir.

Q. And compete in the sale of such gas reserves as may be found and developed in competition with independent producers on an equal competitive footing with those producers, is that right? A. That's right.

Q. Directing your attention basically to the on-system production situation, in the Permian Basin opinion the Commission there generally applied the area rate at the point of delivery by the producer of the gas to the pipeline. In some cases, as you know, it is wellhead and in some cases it was central point in the field, and in some cases it may be possibly other points.

[3186]

If the producer got the area rate at a central point in the field, to the extent that any of his gathering costs or what not were not reflected in the area rate, he would have to absorb them. At what point do you feel under your recommendation that this area rate should apply with respect to pipeline production? A. I think the only other provisions that the pipeline should comply with are those that the producer is directed to comply with in accordance with the order of the Commission. Quality is the easiest one to describe. If they say we fix a price based on thousand Btu gas and if it is below that there has to be a price reduction, then that same price reduction to the producer as to the pipeline.

[3186]

Taking your example, if the Commission says that the price is fixed for gas and that price may be at the wellhead or it may be at a central point in the field, in other words, so that I might be able to buy from Mr. McCorkle's company at a central point in the field but I would have to go to the wellhead to get your gas, but I am still paying the same, then I say we should have the same privilege as the pipeline. They could get it either at the wellhead or the central point. I only feel they should be limited where the producers have the same limitations, because the problem you are talking about gets to be a competitive problem in selling the gas.

Q. That is the point I am trying to focus on, Mr. Elmer

[3187]

There are various reasons why, let's say, in some cases the producer might build lines to a central point in the field and in other cases the pipeline might come to the wells and some of them have to do with the size of the reserves and the competitive situation, so forth and so on. What I am asking about it, again taking the Permian context, if you tell the producer that he gets the same price if he has the same area ceiling whether he sells it at the wellhead or at the central point and you have an on-system produced gas, it would seem to me it would always be advantageous or would it be always advantageous for the pipeline affiliate or the production department to apply that rate at the wellhead and, therefore, retain– A. What if you buy from two? What if you buy from one independent producer at the wellhead and one independent producer at a central point in the field? Now, he buys from his affiliate. You have the right to sell in Permian at either price. It is just how you can bargain with the purchaser; isn't that right?

Q. That is basically it. A. I am saying the pipeline affiliate should be in the same position.

Q. You think he is in the same bargaining position with his parent as we would be with your company? A. That's right.

[3188]

Q. What about a pipeline production department, do you feel they would be in the same bargaining position? A. It is hard to visualize it, but I think you would have to treat it that way. What I am trying to say is we all hope in fixing these area prices there will be as little handtying as possible on the peripheral things such as Btu's and so forth, and I think to the extent there is liberty, everybody should do what is best for them. To the extent that the Commission fixes something that we all have, I think we all ought to live with it. I think your example might be a difficult one because, as I say, you buy from one fellow at the wellhead and the other fellow at a central point, and then you go back and say, "O.K., I will pay myself at the central point", then the guy at the wellhead gets mad. You can't keep everybody happy.

Q. My problem is, as I understand the current method of regulation, the facilities to the wellhead are in the rate base of the pipeline. A. If you buy at the wellhead.

Q. At the present time, and that would be true if it is purchased from the affiliate. As I understand what you are recommending, you are suggesting that at some point take some of the facilities out of the rate base and apply the actual cost experience of the facility. A. Keep in mind we are talking about the future. We

[3189]

are not talking about now. We are talking about what we are going to hook up years from now. We don't have anything in the rate base as there isn't any.

Q. What I am thinking of is the situation where the producers have, if you want to call it, a risk or a chance that they may have to build a certain amount of gathering lines, that they still get the same price as if it were picked up at the well. That is the way Permian happens to work out. It could continue to work out that way in the future. A. In other areas they might want to build the gathering lines.

[3189]

Q. That is a possibility. But in a pipeline situation, as I understand the way the cost of service works, the pipelines' gathering facilities to the well would be in the rate base. Is that right? A. That is right.

Q. And if the pipeline had the option to either say, well, we can do one of two things, we will take the area price, we apply it at the wellhead as the point of transfer and we keep our gathering system in the rate base, and the affiliate doesn't have to build the gathering system, and they get 16.5 cents, and we have this gathering system, on the other hand, if we buy it at a central point in the field, then it seems to me to be an equal treatment with the

[3190]

independent producer in a similar circumstance you would have to remove this section of the gathering system from the rate base. This is the thrust of my question. A. I don't know how to answer it because it is a two-way sword You can turn it around and put it the other way. Let's go away from Permian and let's go to offshore Louisiana.

Q. What I am suggesting, Mr. Elmer, is here is a potential area that somewhat disturbs us, and I am asking basically do you recognize that a potential discriminatory situation could arise here? A. I will recognize that the cost to the pipeline could be less in one case–wait a minute. If the pipeline buys the gas at the central point in the field from your company and buys it from Mr. McCorkle's company at the wellhead, it cost the pipeline company more for Mr. McCorkle's gas than it does for your gas, right?

Q. That is right. A. Now, I come along with an affiliate. Now, what happens? Do you say I should buy at the central point or should I buy and cost myself more and buy at the field? You see, if I buy it at the central point, the affiliate pays the cost; if I buy it in the field, the pipeline pays the cost. But this is what has happened to your two companies.

In other words, you are getting a different price than Mr. McCorkle's company because you have had to pay for the

[3191]

line and he hasn't.

Q. Maybe we should get the Commission to say at a central point in all of their orders. Then you would get rid of this.

Q. It would seem to me the tendency would be in a pipeline dealing with its affiliate or with its own production department to always go to the wellhead because so far as they went to the affiliate or the production department, all those facilities would be in their rate base if they treated it as if it were a central point in the field sale.

As I understand your recommendation, it wouldn't be in anyone's rate base? A. I don't have a recommendation. I don't think it is Tweedlede and Tweedledum. Somebody has to pay for the line, either the affiliate or the pipeline, so it has to come out of somebody's pocket.

Q. I am just raising this not for a complete decision on a broad policy basis as to how this could be resolved, I am asking if it isn't possible it is a situation in which some discrimination might develop in which case possibly the Commission would have to review it. A. I don't agree with the word "discrimination". A price differential develops. By the same token, unless you want to say there is discrimination between the two independent producing companies. For some reason or other, whether one

[3192]

pipeline bargains better than the other or one producer bargains better, it may be a compression problem, for some reason, somebody buys at a central point and somebody doesn't, but you have your option, it depends which shoe you have on. I don't call it discrimination. It may be discrimination compared to one producer, and it is the same as the other producer because you have the same problem among the independent producers.

Q. I would agree to that, and in some cases we sell at the wellhead and we get our 16.5 cents without hav-

[3192]

ing to construct any gathering facilities. In other cases we have to invest money in gathering lines in order to get the 16.5 cents. A. The only answer I can give you is what I have mentioned here earlier today. When a gas pipeline company buys gas from an affiliate, it is not any secret what they pay for it. When they buy gas from themselves, if it turns out they have to file with the Commission sort of a summary or something, it is going to be no secret. This is just a small part of their gas. They have got to keep on good terms with the guy in charge of gas sales of every independent producing company. I just guarantee they are not going to do something to give their affiliate or their department a better shake than they would give you, because the next time you won't sell them the gas. You will sell to someone else.

Q. I think we are beginning to mesh or you are beginning

[3193]

to get the thrust of my concern which is basically, say, hypothetically, Texaco half of the time has to build gathering lines to take at a central point and half of the time it sells it at the wellhead and gets 16.5 cents either way. For an affiliate to come in or a production department dealing with a parent to also get 16.5 cents at the wellhead means that they don't have the additional expense that we have because we are an independent producer for constructing the gathering system. A. Don't you think the next time that fellow came around to that pipeline to sell gas he would have problems?

Q. He might. A. I don't think it is discrimination. I think it is just because the Commission has left the choice there. It is two different companies. I don't know how you could correct it. I don't think it is material one way or the other. It doesn't affect our overall recommendation. We say treat them the same. We are talking about such a small differential.

Q. If you are treating them the same, it would be the affiliate gathering in 50 percent of the cases and not gathering in the other 50 percent as would the producers. I am not trying to come up with an answer this afternoon on how it would be worked out. I am just trying to appreciate whether you think there is something there that would have to possibly be worked out, that equivalent treatment would demand that

[3194]

it would have to be worked out either because, as you say, the pipeline wouldn't be– A. The problem with this type of disucssion is whether you go to a central point or go at the wellhead always isn't a matter of cost differential of gathering. This is what bothers me. I agree with you the price could be different, but that is about all I can say.

Q. Let me move on to a different possible problem, and that is on these deductions. You had mentioned I believe that quality deductions to whatever extent the Commission would require them should apply equally to everybody. You have spoken earlier to the Permian example where the parties agreed on the quality, which will presumably be no great difficulty. But in the Permian situation the parties also agreed on the amount of the deduction, presumably based upon the cost of the pipelines raising the subquality gas to pipeline quality. In that type of situation, do you envision the pipeline affiliate agreeing with the production department–the production department agreeing with the pipeline? A. The same rules exactly.

Q. Again, is not this a potential area where there could be some preferential treatment because of the lack of the– A. I want to be sure I understand. In the Permian case–

Q. The Commission fixed certain quality standards, in the event that gas fell below standards there was to be a downward adjustment in the base area rate. A. This would happen to pipelines. In our example it would.

[3194]

Q. That is what I understand you to be advocating, it would.

Now, the amount of the deduction. There is a mandatory deduction, but the Commission set no amount for the deduction. What the Commission said was, Producer, when you find subquality gas, first you find out how bad it is, and after you find that out, then you and the pipeline decide and file a statement saying this gas is of such and such a quality, the pipeline says it is going to cost so much to raise up, and that so much will be deducted from the rate. A. When this comes, they will work it out on the same basis they work it out with the producer. Again, looking at the future, forgetting some of the old properties, the properties are going to be jointly operated company and owned properties, and what you negotiated with the independent producer will be negotiated with the pipeline division or the pipeline subsidiary. I don't visualize a problem on this one at all, not as much as the other one.

Q. But in both cases, if I understood you this morning correctly, you were suggesting possibly in a dealing between

[3196]

the production department and the pipeline there would be something filed with the Commission that would set out the terms of the deal. A. That is right. I think you would have to have that so there is a record of it.

Q. And you would envision at that time that the Commission would presumably have the opportunity to review that and to take anv action it felt it should. A. You see it isn't like a producer where you start getting paid, they will just advise the pipelines, because when they will show up is when the pipeline has its rate case. This would just go on record. This is what they are going to get for the gas.

Q. Wouldn't you want to know it before? A. They would know. This is just something that we have discussed here. I have discussed it today. I have never had a chance to talk to any staff people about it. I think if they wanted to go this route, they would want some sort of a

record at the Commission level, which would be a public record.

MR. SHIBLEY: I might observe there are times when we file things with the Commission they write us a letter telling us that they disagree.

MR. SLYE: We have had that experience, too.

BY MR. SLYE:

Q. Let me ask you this: To the extent that the pipe-

[3197]

producer or the affiliated producer has a potential for some inherent advantage of the types that we have just been discussing over the independent producer now–I say potential –is it your position that the Commission should through its procedures neutralize any potential advantage by the regulatory treatment of the pipeline producers? A. If we get what we want, if we get comparable treatment, parity treatment, we are certainly not going to abuse it so we lose it.

[3198]

Q. But if you try to abuse it– A. But in whose opinion? To go back again to your gathering thing, in the opinion of the guy that you are buying from at the wellhead or in the opinion of the guy that you are buying from at the central point? We can't write rules and regulations to cover every aspect of everything we do, and I certainly hope when these area prices come out that they leave to the producers as much bargaining room as you can on these things. There is a chance to bargain back and forth, and maybe the pipeline will get a little bit better deal off of you than we can off another company and not tie everything up tight. You are saying let's see if we can't tie it up tight on this. I think you have to leave some flexibility.

Q. Mr. Elmer, I am not suggesting an answer and I am not suggesting that we search for an answer this afternoon. What I am suggesting is there appear to be some potential areas here of non-parity. A. All I will say is there can be

some areas of differentials but not of discrimination, but to the point that you have the right to have those differentials in your own bargaining between you and another independent producer, then the pipeline producer should have the same right.

Q. Again now we are focusing on on-system, and I am not talking about off. A. That is all this whole case is about, on-system.

[3199]

Q. The only thing I am suggesting is that there are–I hesitate to say it again, but it seems to me there are potential areas where you could obtain a regulatory advantage over independent producers. A. No, a trading advantage.

Q. Pardon me? A. Trading advantage.

Q. An economic advantage. A. All right. It is nothing you and I can resolve, I will say that. I know what you are saying, and it is just something that comes from the fact that you are given something I think you should have, and that is leeway to trade on terms and conditions.

Q. To the extent that the Commission finds any disparity in treatment between the way it is working out for the independent producers and the way it is working out for the pipelines and the affiliates, shouldn't it take steps to neutralize such disparity to put them on the even competitive plane? A. I would certainly think they would.

Q. I think we finally meshed, Mr. Elmer.

I have one more short question. Returning for a moment to your comments with respect to these special exceptions that you were discussing–

MR. DIETRICH: That would be on transcript page 708, Mr. Slye, line 25?

[3200]

MR. SLYE: Yes.

BY MR. SLYE:

Q. This is Item 3 on 708, Mr. Elmer, the exceptions thereto warranted by particular circumstances.

To make sure I am clear, you are not recommending that pipelines as a class be permitted to obtain through some exception procedreu either the area rate or the individual company cost of service which ever happens to be higher, are you? A. No, sir. I think and again you are familiar with the Permian decision, it was a similar type of thing put in there to cover the point: Should the Commission find that they have to make an exception some time, they can legally do it.

Q. There was a general statement that they might consider special circumstances and it didn't get much more specific than that. A. But there was a reason for putting it in, was there not?

Q. This was presumably because of the group regulation and, therefore, there might be some special circumstances within the group. What I am trying– A. This is what we are saying here. There may be a special circumstance in an area. Frankly, I don't know. As we said earlier, this would be handled by the Commission. This isn't something that we are recommending. But no class differential, no, sir.

[3201]

MR. SLYE: No further questions.

MR. TALISMAN: Mr. Examiner, I have just one question.

BY MR. TALISMAN:

Q. Mr. Elmer, I don't believe that you have indicated a position on the question of negative tax benefits or spillover. Is it the position of the pipeline production group that to the extent there is a negative tax benefit resulting from production or operations that the pipelines retain the

[3201]

benefit of those as is the case with independent producers if they get tax benefits?

MR. SLYE: I am going to object to the characterization that independent producers get negative tax benefits.

MR. TALISMAN: I said if they do.

MR. SHILBEY: Maybe the question is simply in Mr. Elmer's parity proposal or recommendation of the Pipeline Production Group, does it apply to federal income taxes as well as to the other components; is that about what your question is?

MR. TALISMAN: Yes.

THE WITNESS: That is correct, yes.

MR. REIFSNYDER: I have one question, Mr. Examiner, that was generated by I think one of Staff's questions.

BY MR. REIFSNYDER:

Q. Mr. Elmer, are not the bulk of joint operations those which are dictated by the necessity of meeting space patterns during development rather than joint wildcat operations?

[3202]

A. No, sir; I would say not as far as the pipeline producer in the Texas and Louisiana areas. They come by more often at the state of leasing, itself.

* * *

CROSS EXAMINATION

* * *

[3503]

[Witness Plummer]

BY MR. BROWN:

Q. Do you think that area rate treatment for future pipeline production would encourage or discourage pipelines other than El Paso from engaging in production activities, or do you know? A. I think to some extent it might discourage it; I think to some extent it might encourage it.

Q. Have you made any studies to determine whether or not it would encourage it or discourage it? A. No, sir.

Q. You really don't know? A. I have some opinions about it based on my experience and what I know about the conditions in the industry today. I have some very definite opinions about it, but no studies, no.

Q. Were you present in the room when Mr. Elmer testified on behalf of the Pipeline Production Group? A. Yes, sir, I was.

Q. Did you hear his testimony on this subject? A. Yes, I did.

Q. I gather you disagree with the policy witness for 14 other major pipeline companies in the country? A. I don't disagree completely with it at all. I think that it perhaps will encourage some.

Q. Excuse me just a moment. What will encourage some?

[3504]

A. That pipeline production rates might encourage some of the pipelines–

Q. Area rates? A. Area rates, yes, sir.

–might encourage some of the pipelines to do it. It just seems to me that it has to be that the basic incentive is the staying in business, and why in the world wouldn't it be sufficient incentive for a pipeline? It doesn't seem to me it necessarily follows that you have to make a lot of money over and above cost of service to be encouraged to do the thing that is necessary to keep you in business.

Q. You think area rates will permit pipelines to earn a lot of money over and above the cost of service, is that correct? A. I don't know, and I don't think anybody knows. If you were lucky, as somebody has used the phrase here two or three times on the stand, you might make a lot of money. Under other conditions you might not.

Q. Of course, if you knew that your costs were going to be much higher than area rates, you– A. But there would be no way in the world in which you would know that. Unless this gas has been found and you know how

[3504]

much there is, how much volume of the flow, and what it is going to cost you, you don't have any idea what the rate is going to be ahead of time.

Q. I gather the gist of your testimony is that area rates

[3505]

might encourage some pipeline companies to engage in production activities in the future and would discourage others, is that correct? A. I think that is correct.

Q. Would area rates discourage El Paso from engaging in future pipeline production? A. It certainly would.

Q. It would? A. Yes, sir.

Q. What other companies would it discourage? A. I don't know. It would depend on their own philosophy, their own thinking. I am just telling you you can't say today "Yes, I am going to set out and drill for gas and I am going to make some money." There is no way of knowing that at all. It is a risky business, and if a pipeline company has money they would like to put in that risky business, more power to them. I think some, perhaps some of those up to now who haven't drilled, when they see themselves unable to pick up what they need from the independent producers and they look around at the risk of getting into this business will say "Now, look, I don't know whether we can make any money with area rates or not, and I think we will just take our chances on cost of service. We are not in a high risk business, our income is a regulated income, relatively low, and we are going to stay on the safe side of this business."

* * *

[3515]

PRESIDING EXAMINER: Mr. Plummer, at the risk of over-simplifying what I learned from you today, it seems to me that you told us that the cost of El Paso is higher because of geographical and location reasons, and anybody else operating in that area would encounter similar costs?

THE WITNESS: Except for the override.

PRESIDING EXAMINER: Except for the override?

THE WITNESS: I think that is a fair statement.

MR. TALISMAN: We are talking about in the future now, not the past?

MR. McCORKLE: Why would there be an override in the future?

PRESIDING EXAMINER: Would there be an override in the future?

THE WITNESS: There could be. Assuming the same conditions existed and the same source of gas had to be acquired under the same conditions, there might very well be an override.

PRESIDING EXAMINER: If there is an area rate established that would tend to squeeze El Paso or be unfavorable to El Paso, is that it? Is that the reason why El Paso is against an average area rate and would like to have a cost-of-service rate?

THE WITNESS: No, sir. In the first place, and I think this is importance that everybody understands, today we have ample gas. We are buying an insurance policy. We have a geo-

[3516]

physical-geological organization that costs us a lot of money. We are spending a lot of money to go out and acquire leases, hopefully class A prospects. We are laying this program aside. It is insurance in the event we again cannot get from the independent producer what we need.

It costs money to do that, and at some point in time it may be making us and the consumer a lot of money. I don't know. Right now it isn't. It is a burden on the company. It is true that it is being done somewhat for our benefit, and if we were not in a regulated industry, if we could sell this gas for what it would bring, I would say fine, we will assume those costs ourselves, but the minute you pinch me down to an income that is regulated, then I have got to ask the consumer to pay the relatively small

[3516]

cost of this insurance, which is to insure his future. That may go on three to five years, and during that time it is costing money and I would like it to be in the utility accounts in costing it. If we are eventually successful five of six years down the road, whether that has been drilled by others or us, it comes out two to three cents a thousand, I am a better competitor and the consumer is certainly better off. If he is going to run out and I am going to run out, and the area rate is 18, and I can get it to him for 20, keep in mind I am just talking about the last incremental part of my system that isn't full, I can pay 3 or 4 cents more for my own gas if that is what it takes and still come out with very little incremental

[3517]

incremental increase in the market price if I have to.

So all I am saying simply is we don't run in this risk business, and we are not so sure that anybody in a utility type operation should be in this risk business, but I cannot reconcile myself and I cannot divorce the needs of the operation, the utility type obligations with the necessities of preparing for the future, taking care of whatever may come down the road, and these costs are not going to get imprudent and get far out of line, because the disciplines of the market place will take care of that. It will have to be done prudently, but it may cost a little more, it may cost less. I am going to let the chips fall. We are just going to stay in the type of business we are in. If we have extra capital that we can develop for additional activities, we will put it in less risky activities elsewhere.

PRESIDING EXAMINER: Mr. Plummer, I keep wondering whether you are telling us that if a man has a four-wheel car he needs one spare tire or four spare tires.

THE WITNESS: Your Honor, I have had four flats at once on the pipeline through the desert. He has to have what he has to have.

PRESIDING EXAMINER: You feel he should have four spare tires?

THE WITNESS: Not necessarily. I don't think that the program we are doing in relation to the size of our operation is anything but a one spare tire operation.

* * *

BY MR. TALISMAN:

[3524]

Let me get to this point. The case that you are talking about is 1954. If this case were being held in 1954, I would be plunking for the area rate. But 1954 is not 1967. I would say that the gas business is probably four or five times more risky, the production company in the year 1967 than it was in 1954. As each piece of gas or oil is found, the next one becomes a little more difficult. So you must look at our recommendation as being made for the future in the light of today's conditions. I don't know at what point in time we begin to change our thinking, but certainly the producing industry today has not the same economic conditions, is not faced with the same factors that it was in 1954, and in 1954 I would have sincerely assured my management that on an area rate established as the present one has been, I think we could have gone out and made some money. I am not so sure any more.

BY MR. TALISMAN:

Q. That is the reason for your recommendation in this case? A. Yes. Suppose that you recommend field price, and suppose that the independent producers don't come up with it, and suppose these pipelines start to run out, what are they going to do? Are they going to run up here and take two years to tell a story trying to get area rates overturned so they can get cost of service so they can go out and start hunting for gas? I don't think so. I think you have got to have a

[3525]

basis for the future that insures the availability of the pro-

[3525]

duce for the future, and I think cost of service will more nearly do it than anything else.

* * *

[3581]

Whereupon,

V. M. PLUMMER

resumed the witness stand, and was examined and testified as follows:

* * *

[3599]

MR. DIETRICH:

Q. Coming back to my question, if El Paso were placed on an area rate basis, wouldn't that induce El Paso to operate more like an economic producer than the utility manner of operating which you now claim is utilized by El Paso?

MR. McCORKLE: Are you talking about a comparable basis, Mr. Dietrich?

MR. REIFSNYDER: I don't want to object to this question, but underlying it is the implicit assumption that we are not doing the best we know how today to find gas that we need in the interest of our customers.

PRESIDING EXAMINER: I don't understand it this way. To me his question means we know you are doing the best you can now, but now on a cost basis you have certain limits, on an area basis there may be an incentive. He is asking the witness whether the witness can see the kind of an incentive that would make the company hustle a little more and go for it. I think it is a legitimate question.

THE WITNESS: I think it goes right back to what the

[3600]

profit situation is, Mr. Dietrich. We get area rates established everywhere, and we lose our cost of service basis,

and we are conducting certain activities. We look at them. I would think if there were a profit in it that we might be more apt to spread out all over the country. But at the same time if there were a loss in it and it looked like we had to spread all over the world to recover those losses, we might do that. If the loss were big enough, we might just simply quit and not drill anything at all. I am not sure that any individual or any entity today can take "X" dollars of capital and go out worldwide and successfully explore for oil and gas and make money. I am not convinced of that at all.

BY MR. DIETRICH:

Q. There are a lot of examples of that being done by major producers. A. Starting today, Mr. Dietrich? 1967-68 opportunities? 1967-68 costs? I am not at all sure they can do it.

Q. El Paso is not a novice to the oil and gas game. They have been in it for a score of years, haven't they? A. That is correct, sir.

Q. In fact, you are headed toward becoming an international oil company, aren't you? A. That is debatable. We may become an ex-international oil company awfully quick once any day now.

Q. You have attempted to head in that direction? A. That is correct.

[3601]

Q. In fact, you already have the earmarks, do you not, Mr. Plummer, of operating very much like an independent producer in light of your international operations? A. Yes, but I think what you are now saying infers that, sure, I can be a successful operator in the future if I wrap up and dissipate all the benefits that I have today growing out of my past operations and throwing them on the line, even though it may be losing. I think what you are saying is, sure, I can go out and successfully find oil that costs $6 a barrel and sell it for $3 because I am making a lot of money out of what I found last year.

[3601]

I am just not convinced with 1967 costs and with 1967 conditions and with 1967 opportunities that you can start out and make a success of it. So we might just quit altogether.

Q. Isn't El Paso pretty well spread out all across the country right now? The answer to that is "yes," isn't it?

MR. REIFSNYDER: What do you mean, "spread out"?

MR. DIETRICH: What did the witness mean when he used the term?

THE WITNESS: I meant spread out as an independent producer with leases in all major areas everywhere rather than in limited areas.

* * *

[3615]

REDIRECT EXAMINATION

BY MR. REIFSNYDER:

Q. In view of the questions that have been asked here this morning, in view of your long experience in this industry, do you have an opinion as to why some pipelines have been completely inactive and some have been active in varying degrees in the production business? A. Generally speaking, I think you can classify them three ways.

There is a group that came on the scene early when there was lots more gas than anybody thought could ever be marketed, and when you spaek of buying gas in place there was a time in the history of the Kansas-Hugoton field and in the history of the Permian Basin when you could actually go out and lease gas in place. You knew beyond a shadow of a doubt there was gas there.

We bought a group of leases, we spent all the money we had back in 1939, that didn't have wells within miles, and it was a hundred percent success ratio. So even though we took the lease from the landowners themselves at 50 cents an acre, we were in effect getting proven production. We didn't know at that time when in the world we might be

able to sell it, but Mr. Kapser had foresight enough in those days to spend every time of money he

[3616]

could. You couldn't raise much, it was in the thirties. There was that group that grew up during that period of time, and particularly in the West Texas-Oklahoma-Kansas area. Generally speaking, those people became active in the producing industry and they were active by and large simply with respect to that area.

These leases they acquire then nobody else wanted them.

Then you have the second group who pretty largely came along post World War II, and almost with their birth gas supplies began to tighten up, and the period had long since passed in which you could lease or buy gas in place profitably. Generally speaking, that is the class of producer who has never gone out into the production business. There haven't been any real opportunities for it.

* * *

[3617]

In the overall, El Paso has been a developer also because most of our activities have been spent in San Juan where we were I would say never more than semi-wildcatting except the time or two we went deep, below known areas, but we did wildcat quite a lot through the Rocky Mountain areas and we have wildcatted off shore.

Generally speaking, the pipeline industry has been a developer, and they have developed properties picked up in the days when nobody else wanted them. They have not gone out on a broad scale in wildcatting and exploring for anything as an industry.

[3618]

Q. Based on your experience in the industry, are there any reasons growing out of administrative necessity why you feel there should be any change from a cost of service

[3618]

method of regulation? A. No, sir, and I have trouble with that because I think you not only are not gaining anything, I think you are losing. I am no rate expert, but I have a lot of scars from rate cases, and the simplest kind of a rate case that you can have is a wholly jurisdictional company, no non-jurisdictional activities at all. Then, you take a company that has jurisdictional and non-jurisdictional. It has always seemed to me that your problems with that case growing out of the necessity of allocating between jurisdictional and non-jurisdictional are what makes rate cases difficult, the time it takes to handle one, the difficulties involved. The difficulty that the Commission has in reaching the right answer seems to increase almost with the allocations that have to be made.

If you take a non-jurisdictional or a wholly jurisdictional pipeline or a mix and you put him on the area rate, now you have got a whole world of new allocation problems. With the jurisdictional company, the mixed company, the administrative problems of a rate case increase. With the area rate they increase again. Then, when you think you go to area rates modified, you go from administrative difficulties into administrative nightmare. I think it is a matter that everybody

[3619]

should give serious consideration to.

* * *

[3635]

[MELWOOD W. VAN SCOYOC]

was called as a witness, and, having been first duly sworn was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WHEATLEY:

Q. Would you state your name and address for the rec-

ord? A. Melwood W. Van Scoyoc, 1735 K Street, Northwest, Washington, D. C.

Q. I refer you to transcript pages 983 to 998 and ask you if this is your testimony in this proceeding? A. Yes, sir; it is.

Q. If you were asked the questions there stated would you give the answers as there set forth? A. Yes, I would.

Q. Do you have any corrections or additions to your proposed testimony? A. I do not have any corrections as such, but my attention has been called to the answer to question No. 21, on page 993, where reference was made to the distributor intervenors in the Permian Basin case, AR61-1. I have been advised that the distributor intervenors did not join in the recommended rate of return of 9.5 percent, although the Commission's opinion in that case asserts that they did.

MR. McCORKLE: That is not unique, Mr. Witness.

BY MR. WHEATLEY:

Q. Do you adopt the testimony shown at transcript pages

[3636]

983 to 998 as true and as your testimony in this case? A. Yes, I do.

MR. WHEATLEY: We tender the witness for cross-examination.

MR. REIFSNYDER: We have no questions, Your Honor.

PRESIDING EXAMINER: Who has questions of Mr. Van Scoyoc?

MR. LEITHEAD: I may have a few questions, Your Honor. I would prefer that someone else precede me.

MR. SHIBLEY: We have a few as long as we are here.

MR. LEITHEAD: If Mr. Shibley is not prepared to go forward right now I would be willing to go forward because I do have just a few questions.

[3637]

CROSS-EXAMINATION

BY MR. LEITHEAD:

Q. Mr. Van Scoyoc, would you refer to page 989 of your prepared direct testimony in this proceeding, and specifically to Question No. 15 appearing on that page, and the answer in which you indicate that the traditional cost of service method of rate regulation has been the policy of rate regulation utilized by the Commission for both pipeline companies and affiliated company production. Do you see the reference? A. Yes, sir.

Q. Are you aware that the Commission has applied the area rate method of rate regulation to sales by affiliated producers to their affiliated pipeline company? A. I think they have certainly permitted some affiliated producers to file rate schedules based on area rates, but what I was referring to was litigated cases. So far as my knowledge goes, the policy I refer to here is the policy at the present time.

Q. Are you aware that there were some affiliated producers who were made respondents to the Permian Basin case whose rates were established by the Commission's decision in that case and whose rates for sales to their affiliated pipeline companies were established?

I may be able to help you out here. A. Yes, I was not in the Permian case, and I am not

[3638]

familiar with who all the respondents were in that case.

Q. I specifically direct your attention, Mr. Van Scoyoc, to page 3 of Appendix A of Opinion No. 468 and specifically to the name Lone Star Producing Company appearing on that page. Do you see that? A. Yes, sir.

Q. Appendix A bears the caption or title "Parties and Proceedings Consolidated;" is that correct? A. Yes, sir. Was Lone Star Producing making sales to Lone Star Gas Company in the Permian Basin?

Q. Yes. I was coming to that, Mr. Van Scoyoc, and I will give you a reference in just a moment.

I also direct your attention on page 6 of Appendix A to the name Western Natural Gas Company which I believe was an affiliate of El Paso Natural Gas Company at the time of this particular proceeding. A. I recall there was a Western Natural Gas Company that was an affiliate of El Paso. I don't know the present status of that company.

MR. LEITHEAD: Perhaps Mr. Reifsnyder can help us out. I believe they were at that time.

MR. REIFSNYDER: Until 1963, I think the date was, El Paso did have a stock ownership in Western Natural Gas Company. At that time it was disposed of to, I believe, Sinclair Oil and Gas Company.

[3639]

MR. LEITHEAD: That is my understanding, too, Your Honor, but the Permian Basin case decision established rates for flowing gas which covered a period of time during which Western Natural was affiliated with El Paso.

MR. REIFSNYDER: I should supplement my statement that the stock ownership was in the nature of approximately 19 percent, as I understand it.

MR. JABLON: Mr. Leithead, they established a ceiling; they didn't establish rates, is that correct?

MR. LEITHEAD: Whatever they established, they established for everybody that was respondent to the proceeding in the way of area rates.

MR. JABLON: The opinion speaks for itself.

MR. LEITHEAD: An area rate ceiling, yes, but they did establish rates that applied to all of the respondents in that proceeding.

MR. JABLON: I do not necessarily accede in that statement. If the questions are whether those respondents which were affiliates appear in the appendix to that opinion, fine, but if Mr. Leithead is asking this witness what is the legal effect of the Permian opinion on the rates for these sales or any sales by affiliates to their affiliated com-

[3639]

panies, first of all I am under the distinct impression he is wrong, but whether he is wrong or is not wrong is a matter for brief and is not a matter for this witness.

[3640]

MR. LEITHEAD: I am not asking the witness for a legal conclusion, Your Honor. I am merely asking him in view of the statement that he made that it has been the policy of the Commission to use cost of service in determining rates for pipeline producers and pipeline companies in the past whether he is aware that in this particular decision there were respondents who were affiliates of natural gas pipeline transmission companies and the rates, as I understand it, in that opinion, and I am sure as everyone understands it, that were established apply to all of the sales in that area, whether they were made by an affiliated producer to a pipeline company or not. In fact, I am sure that all of the respondents in that proceeding were required to file statements with the Commission in which they showed the specific rate that they would charge for their sales based upon what the Commission had determined in the way of area rate ceilings subject to adjustments for pressure and Btu content and so forth. I think I am entitled to show that there has been in some instances a different type of regulation applied from the cost of service basis in the past, and I believe that Opinion 468 clearly shows that.

MR. REIFSNYDER: Mr. Examiner, may I make just one statement. I am not taking issue with what Mr. Leithead is now getting to, but so far as to avoid any ambiguity, as of the time that decision was decided, El Paso no longer had an

[3641]

interest in Western Natural Gas Company. I don't want to comment on the argument he is making any further.

PRESIDING EXAMINER: Mr. Reifsnyder, on page 6 of Appendix A the Commission's opinion says so. It says, "Now Sinclair Oil and Gas Company."

Did you wish to be heard?

MR. JABLON: Yes, Your Honor. I am not objecting to Mr. Leithead showing the witness the Opinion 468 and asking him if he is aware of it for the statement. What I do emphatically object to is, first, the legal characterization of the legal effect of the opinion; and, second, implication that assuming Mr. Leithead's premise that the Permian decision would have had some effect on the rates or required some filings that this was or the Commission in any way went to be contrary to its published opinion in Union Producing Company where they specifically established a cost of service. My difficulty is the question doesn't say were you aware of this opinion and does it make you change your conclusion, but were you aware of this opinion to the effect that affiliated pipelines were to be regulated on a non-cost of service basis.

MR. McCORKLE: He has told you how to ask your question now, Mr. Leithead, if you will learn.

MR. LEITHEAD: I do think my question has been rephrased, but I will accept an answer from the witness on that basis.

THE WITNESS: Well, in my testimony starting at page 989,

[3642]

this answer refers to the present policy of the Commission, and we have not had any rate cases involving El Paso, and in light of what Mr. Reifsnyder has said, the sales by Western to El Paso, not being an affiliated company transaction any longer wouldn't be of any interest anyway.

As far as Lone Star Gas Company, there has been no rate case on Lone Star, and whether there would be any significance to that sale in the Permian Basin of Lone Star, I have no idea. I don't know what volumes are involved, and it is my recollection that the Commission's jurisdiction with respect to the rates of Lone Star is very minor.

[3642]

BY MR. LEITHEAD:

Q. I am not trying to take issue with what you have said other than I think your statement was a rather broad one when you said the Commission had adopted a policy of cost of service regulation for pipeline affiliated production.

What I am trying to show here is in fact they did establish some rates in the area rate proceedings that applied equally well to sales by affiliates to their related pipeline company. A. They allowed producers in the Permian to file pieces of paper, rate schedules, which presumably if Lone Star Producing Company has filed a rate schedule in accordance with the Commission's decision, and I don't know about the stay, the effect of the stay in the courts, it may be the legal rate today. I don't know.

[3643]

Q. And in that regard I would like to direct your attention to page 1 of Opinion No. 468, the mimeographed edition, where the Commission describes the boundaries of the Permian Basin area as including Lea County, New Mexico and Railroad Commission No. 7-C in Texas. Do you see that? A. Yes, sir.

Q. And, further, I would like to refer you to the report that is published by the Federal Power Commission bearing a designation FPC S-163 and bearing the title "Sales by Producers of Natural Gas to Natural Gas Pipeline Companies, 1962." In that report, at page 171, are shown seven sales by Western Natural Gas Company to El Paso Natural Gas Company in the year 1962 when the two companies were affiliated.

Do you see that? A. Yes, sir.

Q. Did you know that the Permian Basin opinion established rates not only for gas to be discovered in the future but also for gas that was flowing in 1962 and prior years? A. Yes, sir, both types of gas.

Q. Also, I would like to direct your attention to page 289 of that same report where there is shown a sale by

Western Natural Gas Company to El Paso Natural Gas Company, and that is a report for Texas Railroad Commission District No. 7-C. Do you see that? A. Yes, sir.

[3644]

Q. By the way, the previous reference I gave you at 171 related to sales by Western Natural Gas Company in Lea County, New Mexico, is that right? A. Yes, sir.

Q. Furthermore, on page 289 of Report No. S-163 there is shown a sale by Lone Star Producing Company to Lone Star Gas Company, is that correct? A. Yes, sir.

Q. And that is a fairly substantial volume, wouldn't you say? A. Yes, it is.

Q. In view of this, Mr. Van Scoyoc, would you change your statement at page 989 of the transcript to the effect that the traditional cost of service method of rate regulation has been applied to pipeline affiliates as well as pipeline companies?

MR. JABLON: Objection.

THE WITNESS: No, sir, I wouldn't change my testimony because the issue with respect to the treatment of affiliated company production was not of any particular significance in that case. The most recent cases dealing with production by pipeline company affiliates in a pipeline rate case are as I have stated.

PRESIDING EXAMINER: Mr. Van Scoyoc, would you go as far as saying that the two technical exceptions shown to you merely

[3645]

proves the general rule of policy?

THE WITNESS: I don't think the two exceptions prove the rule, but I think the rule is well known, and there has been a considerable amount of litigation concerning that policy of the Commission.

PRESIDING EXAMINER: In your opinion, then, two

[3645]

exceptions are not sufficient to warrant a statement that the rule is no longer the general rule?

THE WITNESS: That is correct.

BY MR. LEITHEAD:

Q. But the exceptions would indicate that there has been a different method of regulating rates applied in some instances to affiliated producers, is that not so? A. Yes, and there has been a different method applied to pipeline companies, too, at one time.

Q. And you are aware, I assume, that some companies, such as Cities Service Oil Company specifically, had instituted against them rate proceedings under Section 5 of the Natural Gas Act and that those proceedings ultimately terminated in settlement in which the Commission utilized the area guideline rates in establishing rates for sales by Cities Service Oil Company to unaffiliated pipeline companies as well as affiliated pipeline companies?

MR. JABLON: Your Honor, I object unless the settlement is brought in for the reason that unlike an opinion it is

[3646]

general policy at least not to go behind a settlement and not to go into what it is. I have not specifically read the Cities Service settlements and amazingly I have not read the whole background of the Cities Service Company, but I do not believe this is proper cross-examination.

I see Mr. Leithead apparently has an opinion or an order to which he would refer, but I suspect it would have been preferable or would be preferable to do this through his own witnesses, either in rebuttal or at some other time, when we can consider what he is showing either the witness or he is attempting to prove.

MR. LEITHEAD: If Your Honor please, I didn't understand that cross-examination was so limited as Mr. Jablon would have us believe. I think I am entitled to show that the witness may have overlooked certain things in making

the general statement that he has made in his testimony.

PRESIDING EXAMINER: If the witness is familiar with that opinion, he should comment. If it is a matter of interpreting an opinion on the stand, perhaps we could do it on brief.

MR. LEITHEAD: Yes, Your Honor, I agree with you, and I will not ask him to interpret the opinion.

I do have before me an opinion that bears the caption or style "Cities Service Production Company, Docket Nos. G-9510, et al.," which is an order approving rate settlement proposal, as amended and modified, prescribing refunds, severing and

[3647]

terminating proceedings, issued December 26, 1962, and I would merely refer to the paragraph on the first page of that order numbered 1 in which it is stated that "Cities Service's rates for sales of natural gas in interstate commerce, with one exception, shall be at or below the applicable area ceilings."

Do you see that?

THE WITNESS: I am not familiar with that decision or at least I don't recall it.

BY MR. LEITHEAD:

Q. But that is the statement that appears on page 1, is that not so? A. Yes, sir.

Q. Then, appearing on page 1 of the appendix to that order is shown a sale under Rate Schedule No. 86 by Cities Service Petroleum Company to Cities Service Gas Company in the Hugoton field, is that so? A. Yes, sir.

Q. And the settlement price there shown is 11 cents per Mcf? A. Yes, sir.

MR. LEITHEAD: Your Honor, I won't pursue this further. There are other sales in here by Cities Service Petroleum to Cities Service Gas Company.

[3647]

BY MR. LEITHEAD:

Q. Would that paragraph of the Commission's order that I

[3648]

read to you indicate that the rates for Cities Service Oil Company's sales to Cities Service Gas Company, as well as other pipeline companies, were established upon the basis of the guideline ceilings issued by the Commission in their statement of general policy No. 69-1? A. Certainly it indicates that the Commission accepted the results of the settlement and set prices as you have indicated for the various sales, but it was a settlement and I don't think, in my opinion at least, it doesn't demonstrate that the Commission has adopted a policy of pricing affiliate produced gas on the basis of area rates or guideline rates. If that was the policy, I don't know why some of you people are here, frankly.

Q. Mr. Van Scoyoc, I have asked the question on a number of occasions, and I don't know why I am here. Unfortunately, I am.

In any event, this opinion that I have just shown you would not indicate that the policy of using the traditional cost of service approach has been applied uniformly by the Commission to affiliated producers? A. No, I have just said that it hasn't. It hasn't been applied uniformly to pipeline companies either. They finally got back on the track.

Q. There is some dispute about which is the right track, though, in this proceeding.

[3649]

Would you please refer to page 991 of your prepared direct testimony, the question numbered 17 and the answer thereto. You indicate that the Commission departed from the traditional cost of service method in its treatment of pipeline produced gas for rate-making purposes in a Pan-

handle Eastern Pipeline Company case and that the United States Court of Appeals in an opinion reported at 230 Federal 2nd 810 reversed the Commission in this respect. Do you see that? A. Yes, sir.

Q. Are you aware that in that particular proceeding, the Panhandle Eastern Pipeline Company proceeding, the Commission established rates for Panhandle Eastern Pipeline Company's production on the basis of the fair field price? A. They did not establish rates for Panhandle Pipeline Company's production on the basis of a fair field price. They established rates for the sale of gas by Panhandle to its jurisdictional customers, and in determining the cost of service on which those rates were based, they used a fair field price for Panhandle's production in lieu of cost.

Q. You have stated it better than I could state it, that they did use fair field price in determining the rate to be applied to Panhandle Eastern's production that would be taken into their cost of service. A. They did use a field price, as I have explained.

Q. You are further aware that the court did not reverse

[3650]

the Commission in that case but set aside the Commission's determination and remanded the case to the Commission for further proceedings not inconsistent with the court's findings? A. I may be legally or technically in error, but so far as I am concerned it was reversed.

Q. I think the case will speak for itself and I won't pursue that subject further.

Now I would like to refer you, please, to page 992 of your testimony where you indicate in the first sentence of the answer to Question No. 20 that pipeline companies have an assured market for the gas which they and their affiliates discover. Do you see that? A. Yes, sir.

Q. If an affiliate had a substantial amount of property located at a great distance from a pipeline company, let's say at a distance that would not be economic for the pipeline company to connect their reserves, were any reserves

[3650]

discovered by the affiliate, would you say that your statement that the affiliate would have an assured market would apply in that situation? A. Well, my statement was directed to the affiliate whose principal function is to provide gas for the pipeline itself. Mr. Plummer has testified that so far as El Paso is concerned, when they have those sorts of situations, they try to trade it off with some other pipeline company or some other

[3651]

producer. When I made that statement I was having in mind affiliates whose principal activity is finding gas for the pipeline to market.

Q. On the other hand, it would not necessarily apply to the situation where an affiliate is not primarily responsible for supplying the pipeline companies with gas? A. That certainly would not apply. I wouldn't put that on the basis if Humble Oil and Refining is an affiliate of Humble Gas Transmission that their principal duty was supplying gas to that small pipeline. I wouldn't put it that way at all. I would say the same thing with respect to Cities Service Oil Company.

Q. Thank you, Mr. Van Scoyoc.

PRESIDING EXAMINER: Mr. Van Scoyoc, when you use the word "affiliates" you use the Roman word, the Latin version of a true affiliate, don't you?

THE WITNESS: Yes, I am thinking of an affiliate that is controlled by the pipeline or under common control.

BY MR. LEITHEAD:

Q. I would like to refer you to page 993 of your prepared testimony. In the last paragraph on that page you indicate that pipeline companies usually finance a large share of their capital requirements through issuance of debt securites while independent producers generally have little or no debt in their capital structure. What do you term little or no debt?

[3652]

A. I think no debt is quite clear, but little debt I would say maybe five, 10, 20 percent maybe. I wouldn't think over 20 percent would be in the little category.

Q. Ordinarily, though, what you are saying, I believe, is that the pipeline company's common equity capitalization represents something less than 50 percent of their total capitalization, as a general rule, and their debt capitalization, on the other hand, represents something more than 50 percent of their total capitalization?

MR. SHIBLEY: I think I will object to that. I share Mr. Leithead's attitude about this, but I don't believe Mr. Van Scoyoc has made the study that would qualify him to discuss this subject. After all, there is data available. They saw fit not to present it. I do not believe that the witness ought to be permitted to give testimony as though such a study were here before us which we could analyze.

PRESIDING EXAMINER: Do you suspect that Mr. Van Scoyoc is Mr. Leithead's friendly witness?

MR. SHIBLEY: No. I think he is unfriendly, and that is why I said I shared Mr. Leithead's attitude, but I do not want to be necessarily stuck with Mr. Van Scoyoc's rather pervasive answer which I think would be elicited since I don't think it has been shown that he has made the study that is necessary to give any meaningful response.

PRESIDING EXAMINER: Mr. Leithead asked Mr. Van Scoyoc

[3653]

how little is a little. I see no harm in his explaining what he thinks about it. If you think the answer is not well supported or not properly given, you can establish it later.

MR. SHIBLEY: I think he has answered that, Your Honor. The question, as I heard it, was whether independent producers have, generally speaking, less than 50 percent of their capitalization in the form of debt whereas pipeline producers, on the other hand, generally speaking, have more

than 50 percent of debt capitalization. I believe there is no point in having an off-the-cuff opinion on a subject like that in this proceeding.

As a matter of fact, there is a presentation made by Dr. Shaffner. There is likely to be a rebuttal presentation made to it. There is no use in having offhand answers to questions like that.

PRESIDING EXAMINER: Mr. Van Scoyoc, do you know the answer or would you be guessing?

THE WITNESS: No, I would know the answer as far as the general situation, yes, sir.

PRESIDING EXAMINER: Do you still have a question pending?

MR. LEITHEAD: Yes, Your Honor.

[3654]

PRESIDING EXAMINER: And you want an answer?

MR. LEITHEAD: Yes, I would like to have an answer, yes.

THE WITNESS: I would say generally pipeline companies have debt capital of 50 percent or more, most of them more; whereas, independent producers generally have less than 50 percent debit capital. Of course there are exceptions in both categories.

BY MR. LEITHEAD:

Q. In the case of an independent producer which fell within that exception in the Permian Basin area rate proceeding, for example, his rate of return would have been determined in the same way that all of the other independent producer rates of return were established; is that right?

A. I didn't know that the Commission determined a rate of return for any particular producer in the Permian Basin case.

Q. His rates would have been determined in the same manner and the 12 percent rate of return that the Commission determined for flowing gas as well as new gas in that manner would have applied equally well to all produ-

[3656]

cers whatever their capitalization? A. The rate of return which the Commission used to determine a ceiling price in the Permian Basin case is what you say, on 12 percent. That doesn't mean any individual producer is going to earn 12 percent on his gas sold in interstate commerce.

Q. I understand what you are saying, Mr. Van Scoyoc, it

[3655]

is possible that some producers might earn as much as 30 percent and some might earn one or two percent? A. The possibility exists.

Q. And this application of the 12 percent rate of return, or whatever it might be in Permian Basin, applied across the board without respect to what the producers' particular capitalizations were? A. That is right.

MR. LEITHEAD: Thank you. That is all I have.

BY MR. SHIBLEY:

Q. Mr. Van Scoyoc, I believe you refer in your testimony to the prior interest which you have taken in the field of pricing company-owned gas? A. Yes, sir.

Q. Apparently it extends back at least to the Docket G-580 investigation which was commended in 1945 and concluded in the latter part of 1947. A. Yes, sir; so far as my active participation in that matter.

Q. While we are on the subject of history, what conclusion did the Commission reach with regard to the best regulatory method for treating pipeline owned gas in that G-580 investigation? A. There were two Commission opinions, so-called, one by Commissioners Olds and Draper, which held for the traditional

[3656]

cost-of-service method, and one by Commissioners Smith and Wimberly, which held for the field price or commodity value. There were only four Commissioners, so we had two reports.

Q. So it would be fair to say, not from your own standpoint, but from the standpoint of someone who didn't have a pronounced view as to just how it should be done, there was probably at that point a fifty-fifty chance of having commodity value as against a fifty-fifty chance of the traditional individual company cost method insofar as the Commissioners were concerned? A. So far as the Commissioners were concerned, I would say for that particular period of time there was a fifty-fifty chance, and that issue was reconciled by the appointment of a fifth member to the Commission shortly after that.

Q. That was Commissioner Buchanan? A. Yes, sir.

Q. They didn't decide any cases involving pipeline production during Commissioner Buchanan's tenure, did they? A. I am pretty sure they did. I think the Virginia and West Virginia Gas Company and the Kentucky Gas Company cases were decided at that time, 7 FPC 112. I believe Commissioner Buchanan participated in that decision. As I recall, there was a dissent in that case.

Q. It still wasn't a hundred percent clear? A. There has been difference of opinion on this issue on the Commission I think pretty generally throughout the years.

[3657]

Q. According to the report which I am looking at, Commissioners Wimberly and Smith dissented and Commissioner Olds concurred; is that your recollection of the situation? A. Yes, sir.

Q. About that period of time I believe you were involved with a legislative effort to provide how pipeline owned gas should be treated as well as independent producer owned production; is that correct? A. Yes, sir. There were several bills in Congress which would have granted to the pipeline companies and their affiliates a so-called commodity value, fair field price, or the market place, whatever it might be.

Q. Generally speaking, the same thing as the independent producers were getting? A. Well, it would take that

function completely out from under the Commission's jurisdiction so far as using a cost method of regulation with respect to pipeline producers and their affiliates. The various schemes varied somewhat from bill to bill.

Q. Actually, you opposed that form of legislation at the time, didn't you? A. Yes. At that time I was Assistant Chief of the Commission's Bureau of Accounts, Finance and Rates, and I prepared or assisted in the preparation of reports to Congressional Committees. I think I testified before I think the House

[3658]

Interstate and Foreign Commerce Committee on one of the bills.

Q. That bill was actually passed? A. I testified in opposition to that bill.

Q. That bill was passed, was it not, by the House in the form which you opposed it? Wasn't that the Lyle bill? A. No, I think this came before the Lyle bill.

Q. The Moore-Rizley? A. The Rizley. It passed the House I believe and was never reported out of the Senate Committee.

Q. Then the succeeding legislation passed the House and the Senate and met with a Presidential veto? A. You are referring to the Kerr bill?

Q. Yes. A. No, that did not take pipeline production out of the Commission's jurisdiction. It was limited only to independent producers. That is my recollection of it.

Q. Did you appear in opposition to that also? A. Yes, but not as a member of the Commission's Staff. No, I did not appear on that. I did not testify on the Kerr bill.

Q. During the period in which the Moore-Rizley and the Lyle bills and the other bills were pending, with the prospect or at least the intention of their proponents of achieving generally the same type of treatment for pipeline producers as others, are you familiar with whether the pipeline producers were at

[3659]

that time increasing or decreasing their production activities? A. I believe the pipeline producers have steadily increased their production activities over the years.

Q. In 1954 in the matter to which you referred in response to Mr. Leithead's question, the Panhandle Eastern Pipeline Company proceeding in which the Commission undertook to provide substantially the same revenue to the pipeline producer as the independent producers were achieving, you were in opposition to the Commission's decision in that matter; isn't that correct? A. Yes, sir. I recommended to the Commission against change of policy with respect to the treatment of pipeline company production.

Q. Actually, your voluntary departure from the Commission was the result of their failing to follow your recommendation in that case; isn't that correct? A. That decision and the prospects for the future did have an effect on my leaving the Commission; yes, sir.

Q. In the period after the Federal Power Commission granted the commodity value treatment to Panhandle and to El Paso, and when the result appeared to be Commission policy prior to the determination by the courts to which you referred, did you look to see what type of stimulous, if any, was given to pipeline production? A. Not right at that time, but in connection with my

[3660]

appearance as a witness in several rate cases, I am sure I looked in to that, and I put in some exhibits in those cases which showed the trend of pipeline company participation in exploration and development activities over a period of years.

Q. You recall, do you not, that pipelines such as Panhandle Eastern Pipeline Company, for example, that there was a marked acceleration of exploration and development and other production activities that occurred immediately following the Commission's decision in the Panhandle case in 1954?

MR. WHEATLEY: I am going to object to that question because that is directly contrary to what Mr. Elmer said. He dated it as 1960. He said up to that time pipeline companies thought it was cost of service, and at that point with the Commission's decision in 1960 in the independent producer case, at that point they decided that cost of service was dead.

MR. SHIBLEY: I don't understand that is a basis for objection, Your Honor.

PRESIDING EXAMINER: The witness should answer the question.

THE WITNESS: Mr. Shibley, I do not recall now whether Panhandle accelerated its exploration and development program following the decision of the Commission in that case or not. I know I have some papers at the office which would show what the facts are, but I just don't recall what they are right now.

BY MR. SHIBLEY:

Q. Perhaps if you return tomorrow you will bring the

[3661]

papers along with you? A. If you would like me to, I will be happy to do so.

Q. At the same period, namely, 1954, as we all know the Phillips case was decided and the independent producers were subjected to the prospect of Federal Power Commission regulation of the rates. You have referred to the fact that you have appeared I think you said seven independent producer rate proceedings.

Without taking a lot of time on the subject, would it be fair to say that your recommendation in those proceedings was based on an individual company cost of service treatment for the independent producers? A. They were with the exception that in the South Louisiana area rate case in which I testified the cost allocation which I put in was based upon not individual cost of service but composite cost of service.

[3661]

Q. You say it was based upon it, but the fact was you certainly weren't embracing the area cost concept; you were indicating that you didn't think it would work, weren't you? A. No, I didn't say in my testimony that I didn't think it would work. The Commission had committed itself to that method, and I think my testimony was to the effect that I hoped it would work, considering all that was being put into it. I would have to refresh my recollection on that, but I don't think I ever said—I am sure I didn't say in that case that it

[3662]

wouldn't work.

Q. Let me see if I can't help you refresh it. I am referring you to Part 8 of volume 12 of the transcript in Docket No. AR61-2.

At transcript page 3693—and this will at least finish up my questions on the seven prior cases in a rather succinct method—you were asked by your own counsel:

"Mr. Van Scoyoc, did you testify in a number of independent producer rate certificate cases before the Federal Power Commission during the past several years?

"Answer: Yes, I believe I testified in seven producer cases."

Question from Mr. Goldberg, your counsel:

Q. In these instances has it been your position that producer rate determinations on an individual producer cost of service basis is a workable, feasible, and satisfactory method of rate regulation?"

Your answer was: "Yes, sir."

"Are you still of that opinion?"

And the answer is "Yes, I am."

You recall that testimony, don't you? A. Yes, but that is far different than the way you categorized my testimony.

Q. We will reach that point.

First of all, are you still of the opinion that individual

[3663]

company cost-of-service treatment is a workable, feasible, and satisfactory method of rate regulation for independent producers? A. Yes, I think it can be done that way. It was done in a number of cases.

PRESIDING EXAMINER: We will now take a short break.

(Whereupon, at 3:10 p.m., a recess was taken until 3:30 p.m. of the same day.)

PRESIDING EXAMINER: The hearing will come to order.

BY MR. SHIBLEY:

Q. Mr. Van Scoyce, let me ask you if you recognize this testimony:

"I am very much concerned that the area price procedure, regardless of however one may try to make it work, will turn out to be a dismal failure after an expenditure of a tremendous amount of money"; does that– A. That might have been my testimony, but not in the area rate case.

Q. That was your testimony in Natural Gas Pipeline Company of America, December 5, 1961, at page 2132, RP61-8.

You recall, of course, that that testimony was given after the Commission had announced the area rate approach? A. Yes, back at that time, and I don't know, we are not out of the woods yet. It is up in the Supreme Court.

Q. It may still turn out dismal?

[3664]

A. I hope it does turn out to work in view of all that has gone into it in this intervening period.

Q. Turning to your testimony in this case for a moment, on page 990 of the transcript, volume 8, part 2, you are making the point here, as I understand it, that the public utilities are really quite similar to pipeline producers and

independent producers, and you use as your only method of demonstrating that the ratio of production net investment to revenue. Have I fairly summarized the situation? A. I am afraid not, Mr. Shibley.

Q. Straighten me out. A. I was referring to the fact that production of gas requires a large capital investment in relation to annual income, and to demonstrate that point I compared the ratio of production net investment of the Appendix B and C producers in AR61-2 with their revenues and also compared the pipeline investment-revenue ratio and the electric utility investment ratios, and then I went on to discuss that. There are, of course, differences but in my judgment they were not so great as to make the use of the cost-of-service method inapplicable to gas production.

Q. For both independent producers and pipeline producers? A. Yes, sir.

Q. Unless I misunderstood you, the only part of my statement with which you disagreed was my stating that what you were trying to demonstrate was that pipeline producers and independent

[3665]

producers were so similar to public utilities that the cost-of-service method if applicable; you are certainly not disagreeing with that part of my statement either, are you? A. No, I say that the differences are not sufficient to negate the feasibility and workability of a cost-of-service approach with respect to producers. Now, the Commission has used a cost-of-service approach with respect to producers in AR61-1 on a composite basis rather than on an individual producer basis, but it is still a cost of service approach.

Q. You couldn't really get much closer than this 2.08 ratio which is applicable to the independent producers and the 2.03 ratio which is applicable to the pipelines? In other words, that is just about an identity? A. Yes, they are very close together. There is no doubt about it.

Q. And those figures are both on a composite basis; they are not individual bases, are they? A. Yes, they are on a composite basis.

Q. And actually this particular answer to which I am referring and to which you have stressed dissimilarity, is a verbatim reproduction of the testimony that you gave in the AR61-2 area rate proceeding for independent producers; isn't that correct? A. It could well be. I am glad you pointed out my consistency.

[3666]

Q. Except for the question which let me read you in that case at transcript 3695:

"Q. Is it correct that the production of natural gas is so different from the operations of public utilities that the cost-of-service method is less applicable, if at all, to the gas-producing industry?"

Your answer was "No, not in my opinion."

The next question was "Would you state the basis for your opinion?"

And then you answered that question by using the same which you said at transcript 990 in this proceeding whereas, however, the question is, and get this: "Has the Commission's use of the individual rate base approach for the regulation of the price allowed for pipeline and affiliated produced gas proved to be workable and feasible?"

You answer here "Yes," and then you go on with this discussion of the virtual identity of the utility ratio with the producer ratio of revenues to net investment.

Have you looked at any individual company ratios of revenue to net investment for the pipeline producers? A. Not in connection with my testimony here. I have certainly looked at them over the years, Mr. Shibley.

Q. Do they as an individual company matter fit this 2.03 to 2.08 range or do they have a wider variation on an individual company bases? A. As far as the individual companies, I would expect them

[3667]

to vary both up and down from the 2.03. There will still be a rather heavy investment per dollar of revenue in pipelines. Unless they have leased property, or something like that, I do not think you would get down to a ratio of probably one and a half on the low side. It might go up to 3 or 3-½ on the high side, depending on the individual situations.

As I said, I haven't looked at any figures along that line recently.

Q. If they had a variation between one and a half and three and a half, the range would be something in the order of 220 percent. A. It could be. There could be individual situations where you might have that spread.

Q. Could you have that much spread for the independent producers in your opinion; that is, the elements of the composite which make up this 2.08 composite ratio? A. Yes, I think you could have a fairly substantial spread there.

Q. If you took high range of the high independent producer and found that it was more than twice as great as the low independent producer in terms of this ratio, would you reach the conclusion that as to that particular producer it was sufficiently dissimilar from the composite or the norm and sufficiently dissimilar from your public utility ratio that you wouldn't use the same pricing method here?

[3668]

A. I don't know, Mr. Shibley. I don't think it would have any effect, but I think I would have to look at the individual situation and all the facts and circumstances relating thereto.

Let me say first that so far as these ratios are concerned here, that is not on which I rest my view that a cost of service method is workable and feasible for pipeline companies. I think it would enter into it a little more with the independent producers. I am thinking of independent pro-

ducers in comparison with, say, the grocery business or something where you might have a ratio of revenue which may be two or three times the investment, where you would have that type of a situation. But the independent producers as well as the pipeline companies are in capital intensive industries. It takes a lot of capital to do the job, and they have a lot of capital invested at all times.

Q. That would be true of the individual pipeline producers, individual independent producers, and the groups as a whole? A. Yes, sir.

Q. In that same case that we were referring to a moment ago, the Natural Gas Pipeline Company of America rate proceeding, in Docket RP61-8, you testified at page 2150 in response to questions from Mr. McDugald: "I feel that the producer should be compensated for selling his gas in interstate commerce on the basis of giving him a price or rate for his gas which will cover

[3669]

his operating expenses, giving him a return of his capital and a fair return commensurate with the risks of the business."

The next question to you was, "Are you completely catholic in your thought here? You make no distinction between producer whether he is a big producer, little producer, pipeline producer or otherwise," and your answer was "No, I make no difference in principle at all."

Is that a fair statement of your views? A. At the present time?

Q. Yes. A. Yes, sir. I am dealing with principles there.

MR. SHIBLEY: Those are all the questions we have.

PRESIDING EXAMINER: Who has further questions of this witness?

MR. JABLON: Staff has a couple.

[3670]

BY MR. JABLON:

Q. My name is Robert Jablon. As I believe you know, I represent the Commission's Staff.

Referring to your cross-examination earlier this afternoon by Mr. Leithead, I would like to ask you whether you know if the Commission established rates what rates would be applied in individual company cases of the transmission segments or affiliates of pipelines with relation to the produced gas of their affiliates in the individual pipeline rate case? A. Well, I recall that in the Union Producing case the Commission did make a finding as to the rates of Union Producing or the prices that Union Producing would charge its affiliated pipeline company, United Gas Pipeline Company, and since most of the pipeline rate cases have been settled, there have not been too many decisions of the Commission dealing with pipeline production for quite a while. I recall that there was the case involving Northern Natural Gas Producing Company where the Commission made it pretty clear—I think that was about 1963 or thereabouts—that they considered Northern Natural Gas Producing Company the producing arm of Northern Natural Gas Company, and that they would determine their costs as a basis for the gas which they sold to Northern Natural Gas Company, but later that case was settled, so the Commission did not make a decision in the case.

Right now the only one I can think of in recent years is

[3671]

Union Producing Company. But, of course, before that, going back into you might say the early cases, we had situations involving Texoma Natural Gas Company and Natural Gas Pipeline Company, the Canadian River Gas Company, Colorado Interstate. Cities Service had some affiliates in the early days that were selling gas to Cities Service Gas Company. I believe there was some adjustment made there.

There have been some others, too. I just don't recall right at the moment.

Q. But to your knowledge the Permian decision itself did not decide the price for purchased gas which would be imputed in pipeline rates for sales which were made to the pipeline by its affiliates? A. In my judgment, it did not.

Q. My next and last question again refers to the cross-examination of Mr. Leithead.

MR. LEITHEAD: Is this redirect examination, Your Honor?

MR. JABLON: No, this is I guess in the nature of re-cross. But really I would like the witness' opinion on this.

BY MR. JABLON:

Q. There is always a danger in categorizing a witness' testimony, but I am going to attempt it.

I believe that you stated that you meant to apply cost of serviçe principles to affiliate sales of affiliated producers which were functioning in an affiliated relationship with the

[3672]

pipeline company but did not necessarily mean to include or meant to exclude from this recommendation other affiliates, such as Cities Service or Humble, I believe you mentioned, which were functioning essentially as independent producers.

My question to you, and it is a broad one, is whether you can give for the record the characteristics or categories or considerations which would enter into classifying affiliated producers as either an affiliated arm in the functional sense which would get cost of service under your recommendation or a non-affiliated producer in a functional sense which apparently would get the area rate or some other treatment?

May I add as an addendum, I recognize I am asking a long question, and I really would like your views as to

[3672]

what the policy should be without attempting to categorize or refine you to a specific word formulation by myself.

A. I am afraid I might have to give you a long answer to your long question. As I look at the situation dealing with affiliates, and it is a difficult one in some respects, I think we have to be practical in regulation. I don't care what we are regulating, we have got to be careful about it. We can't just rely on theory alone, no matter where it leads us. I think you have to look at each individual situation and consider it. If there is an affiliate, and I view Cities Service Oil and Humble as examples, as in my previous answer to Mr. Leithead, whose primary objective is the exploration and development of oil

[3673]

and gas resources on a nationwide or a worldwide basis and who is not primarily—and I know I am using adjectives that are hard to define—whose primary job is not the production department of an affiliate—for example, Humble Gas Transmission Company is the third or fourth name I think for the same company, it is my recollection, and it was originally started by Standard Oil Company of New Jersey as one of its companies, and they sold out to Olin, I believe, and Olin sold it to Humble, and there may have been, I think, Carter Oil Company originally before Interstate Natural Gas.

Through Humble's recent acquisition, more relatively recent acquisition of Humble Gas, it sells somewhere around, I think, 40 million Mcf a year to Humble Gas Transmission, which is a fairly substantial part of its total gas supply at the present time. I think the importance of that volume in relation to the total gas supply of Humble Gas Transmission is of a significant magnitude to warrant a study made to see whether those particular reserves which supply Humble Gas Transmission can be carved out of Humble, the parent, and determined on a cost of service basis. It may be when you get all through with that you will find that the costs and

the area rates may be the same. They may be a little higher, they may be a little lower, or there may be substantial variations. Depending on what you find, then, I think the Commission can decide whether they want to treat it as a producing arm of Humble Gas

[3674]

Transmission and use cost of service or whether they want to use the area rates. It may not make any difference.

However, I think it would be incumbent to look into that, and if I was in a rate case involving Humble Gas Transmission, I would want to look into it regardless of the fact that the Commission may have in an area rate case determined a maximum rate for that particular sale of gas.

On the other hand, let's take a situation, and I don't have one particularly in mind, so it will have to be hypothetical, where there is a major producer of oil and gas with wide exploratory operations and it has an affiliate that is a pipeline company, but the amount of gas which that major producer sells to this particular affiliate is insignificant in relation to the total gas supply that this pipeline has. The amount of cost that is involved is very small in relation to the total cost of purchase gas. In a case of that kind I would be inclined, as a practical matter, to ignore it because I don't think it is worth while to spend the time and effort to try to go in and carve out of the operations of this major oil company maybe a field or a couple of leases somewhere.

So I think you have to treat each one of these as an individual situation depending on the facts and circumstances, how this affiliate arose, how the gas reserves were acquired, what is the company's policy, and that sort of thing. I don't think you can classify these affiliates without making that

[3675]

type of study.

Q. If I may follow that up, as I understand it, the first test was the proportionate amount of sales or the proportionate costs of the total gas supply of the pipeline which came from the affiliated producer, is that correct? A. Yes, sir.

Q. A second test which I believe I caught was the history of the relationship I presume in terms of (a) financing, and (b) acquisition of reserves, is that correct? A. Yes, and the general policy of the pipeline company if it is a parent of the affiliate in using the affiliate, putting it into the exploration business.

Q. The reason I am trying to break it down is the difficulty in the determination of the conclusory word: the "policy" of the company, and I was wondering what tests we might derive to determine pragmatically what that policy was. A. I think that can probably only be determined on a case by case basis through an investigation. The Commission has made determinations, for example, in Union Producing Company, that it was a producing arm of United Gas Pipeline Company. In coming to that determination the Commission had before it evidence of the historical, the proportion of sales, how they operated, common officers and directors, and that sort of thing.

Q. I assume financing also?

[3676]

A. Yes, financing, how it was financed.

Q. Would you make any distinction between on-system and off-system sales of affiliates? A. Yes, I would make a distinction between those, and there again it goes to the question of degree of the off-system sales. I think Mr. Plummer's approach, which he spelled out this morning, makes considerable sense, but if you have an affiliate that is exploring widely and not conducting its operations pri-

marily to supply gas for a particular pipeline company, then, yes, I think you have to make an allocation and sort out the off-system sales, and I think as far as the off-system sales are concerned, the area rates would undoubtedly apply.

Q. I have one other question which probably is assumed. In your illustrations of Humble Gas Transmission and Cities Service, am I correct that you were using these examples of illustrations which might have to be looked into rather than making definitive recommendations as to the proper treatment of those companies? A. Oh, yes, purely as examples.

Although I have some general knowledge, I have not made any specific investigation, and I wouldn't want to categorically say how I would treat them at the present time.

MR. JABLON: Thank you. Staff has no further questions.

BY MR. BROWN:

Q. Mr. Van Scoyoc, you just described to Mr. Jablon the

[3677]

distinction you would make between the on-system and off-system sales of an affiliated producer. Would you, sir, make the same distinction between the on-system and off-system sales of a pipeline that produced gas through a production department rather than an affiliate? A. Yes, I would make the same distinction, but there again it would depend on individual circumstances. For example, I remember Hope Natural Gas Company in their search for gas in the Appalachian area punched holes and found a couple of oil wells as a result of it. I think at that time the revenue from that oil was credited to the cost of service. It was a minor matter. I think this whole thing comes down to degree and practicality as to how you would treat these

individual situations where a pipeline company or an affiliate of a pipeline company makes off-system sales.

MR. BROWN: I have no further questions.

MR. JABLON: May I have one follow-up?

BY MR. JABLON:

Q. You don't have any specific tests which you would apply as to what amount of sales from an affiliate by a pipeline you would consider significant? A. No, sir, I don't have any mathematical test for that. It is a question of judgment in the light of all the facts and circumstances.

BY MR. STANSFIELD:

[3678]

Q. Mr. Van Scoyoc, I am E. A. Stansfield and I am representing the Public Service Company of Colorado, and I am sure from your experience, both in the Commission and subsequent in your private practice, you are familiar generally with the operations of the Public Service Company of Colorado, particularly in the gas area, is that not correct? A. Yes, sir.

Q. Again I should state for your information that we are an intervenor in this proceeding only.

I would like to refer you to transcript page 990, particularly to the second sentence of your answer to Question 16 of the folio page 8, that sentence beginning "It has also been feasible to make a reasonable appraisal of the risks of the gas production business and to provide compensation for these risks in the rate of return."

From your great knowledge of this entire operation, could you tell me just how this has been done and perhaps give one or two examples? A. Well, the most recent examples I believe involve the last Southern Natural Gas Company rate case where Southern Natural specifically requested a higher return on its production department investment than it did on its pipeline department net investment. The Commission discussed the pros and cons of that

and concluded that any significant difference in risk had not been shown by Southern Natural.

[3679]

Then, of course, there was a Union Producing case which involved its risks, and that company is entirely in the production business.

Of course, the Commission in the Phillips case made a determination so far as Phillips risks. The same thing in the Area Rate cases. So the Commission has made appraisals of the risks of the production business, both pipeline and independent producer.

Q. Have they made provision for the compensation for these risks in the rate of return with respect to a pipeline producing company? A. Yes, they have.

MR. REIFSNYDER: Could I have a definition of the term "pipeline producing company"? Do you mean an affiliate?

MR. STANSFIELD: No, I did not intend to include an affiliate in that definition.

MR. REIFSNYDER: You were referring to a pipeline production department?

MR. STANSFIELD: A pipeline production department or a pipeline company that has its reserves not through an affiliate.

THE WITNESS: That is the way I understood it.

MR. TALISMAN: Didn't you just say a moment ago that the Commission in the Southern case concluded that Southern should get its same return on its production operations as it does on its pipeline operations?

[3680]

THE WITNESS: That is right.

MR. TALISMAN: It seems to me that was inconsistent with your answer to the last question. Maybe I am wrong.

THE WITNESS: I don't think so. I understood Mr. Stansfield's question to be whether the Commission has

[3680]

fixed a rate of return on the production business of a pipeline company which would compensate for their risks, and I said yes, they have, they have done that in many cases.

BY MR. STANSFIELD:

Q. But Southern Natural would not be an example of that? A. Yes, it was.

Q. I understand they gave no additional compensation. A. They didn't give any additional, but they found there was no difference.

Q. They made an appraisal, is that not correct? A. They made an appraisal and found that Southern had not sustained its burden of proof that there was a difference in risks to be recognized in the rate of return for the production net investment as distinguished from the pipeline investment.

Q. May be I am making this complicated, but, as I understand your answer, and again going back to the question "It has also been feasible to provide compensation for these risks in the rate of return," in Southern Natural, at least to my knowledge, the Commission did not provide for compensation for

[3681]

anything in the rate of return other than to conclude what you have stated they concluded that the rate of return they would have given was satisfactory? A. Well, the rate of return they gave them provided all the compensation they thought they were entitled to for that particular business.

Q. Again on transcript page 993 and again with respect to the answer to Question 21, can you give the allowance on equity that would be given to a pipeline company which would have a rate of return of 6.5 percent, such as you mentioned, on an average? A. You will have to assume a capital structure and a cost of debt in order for me to give that to you. I could only give you a hypothetical example right now by making a calculation.

Q. Well, I think perhaps you refer in your answer to the highest rate of return which the Commission has allowed. Would you have in mind the equity on that particular company?

MR. TALISMAN: I can speak for Midwestern Gas Transmission Company. It was about 8.5 percent on equity. They received 6.5 percent overall return.

THE WITNESS: The rate of return on equity depends on the capital structure, and, of course, the cost of debt capital, and that will vary from pipeline company to pipeline company. But I can say very generally—again there are exceptions, as Mr. Talisman just pointed out on Midwestern—the rate of return on

[3682]

equity on pipeline companies has run around 10 percent.

BY MR. STANSFIELD:

Q. Can you give the allowance on equity that was granted by the Commission in the Permian case?

MR. JABLON: Your Honor, I am going to object to that unless the question encompasses whether there are comparabilities being compared, and I have specific reference to the fact that in pipeline cases normally there is not an added dimension as there was allowed in the Permian decision for the risk of finding deficient gas in quality.

MR. McCORKLE: I object to Staff counsel making the decision. Let's let the Supreme Court decide that. It is going to hear the case next week.

MR. LEITHEAD: I think there is quite a bit of doubt as to what was included in the Commission's determination of the 12 percent rate of return.

PRESIDING EXAMINER: Mr. Van Scoyoc, did you participate in the Permian case?

THE WITNESS: I did not, sir.

PRESIDING EXAMINER: You would only give us your interpretation of the decision there, is that right?

[3682]

THE WITNESS: That is right.

MR. McCORKLE: Let it speak for itself.

THE WITNESS: I could only go by what the Commission sand in its opinion in giving you any answer, and I don't have the

[3683]

opinion with me. I thought maybe another document might show that, but it does not.

MR. JABLON: Your Honor, if I may state, I agree completely with the comments here that the opinion should speak for itself. My difficulty is that the questions, as those by Mr. Leithead to which I did not object this morning, now seem to continue to assume a specific rate of return on equity or generally in Permian, and without comment the record would read as if there were no difference and as if there were no problems taken into consideration, and being that this is before the Supreme Court, Staff counsel is perhaps overall sensitive about this, but we feel it is important to bring out that in this instance the figures in fact are not comparable and any question and answer on a bare record based on an assumption of comparability might be misleading and might in fact be quoted out of context.

PRESIDING EXAMINER: Mr. Stansfield, the witness doesn't know the answer to your question.

Do you have another question?

BY MR STANSFIELD:

Q. I would go back to transcript 991, and again your answer to Question 18 of the folio. In answer to this question you state, "Irrespective of the purpose of the allowance, whether it be to encourage exploration and production activities, or any other reasons, the test would be whether such an excess is in fact needed and is no more than is needed, for whatever purpose it would presume to accomplish."

[3684]

If the Commission ultimately in area rates establishes for independent producers an allowance on equity specifically in an amount to encourage development and exploration, and assuming that that allowance would be greater than the allowance on equity granted to producing pipelines generally under the conventional rate method, would this be an amount which would be in excess of those which would result in the use of normal rate method that you would consider to be proper for a producing company? A. I don't know, Mr. Stansfield, without examining the individual situation.

The rate on common equity is a function, as I said before, of the capitalization ratio as well as the cost of debt, and I don't think it is appropriate to compare the equity earnings on the fair rate of equity capital of a producer which may have no debt in the capital structure or five or ten percent with a pipeline company which has a debt ratio of 50 to 75 percent.

Q. I appreciate that, Mr. Van Scoyoc. A. The risks are different.

Q. In your conclusions at transcript 997 you do state that "The incentive which prompts the commitment of capital to a regulated enterprise is the opportunity to earn a fair return."

Would you have any opinion on what a fair return on the equity for future pipeline production investment would be,

[3685]

recognizing the current costs of money? A. I wouldn't venture an opinion without studying the individual situation, Mr. Stansfield, as to what the fair return for a pipeline company would be. I can only say that it ought to be based on the cost of capital to a predominant degree.

Q. Referring to transcript 994, page 12 of the folio, and again the last sentence in your answer to question 21 where

[3685]

you state "Moreover, pipeline producers which could not earn a reasonable rate of return on their net investment in production facilities under area rates might experience increasing capital costs which would be a burden on the consumers."

Do you see that statement in your testimony? A. Yes, sir.

Q. Does this suggest that if area rate ceilings are established that an inefficient pipeline producer should be granted cost of service rather than area rate ceilings to cover his inefficiencies? A. I am not certain that I understand that question completely. May I have it be read?

(Question read.)

THE WITNESS: I am not sure I understand your question, Mr. Stansfield. I am not trying to evade it at all. You are suggesting that if the Commission should adopt an area rate for pipeline future production and some pipeline goes into the production business, or maybe a pipeline who is already in the pro-

[3686]

duction business goes ahead on a grand scale and finds that their costs are substantially in excess of the revenue that they are going to get from this gas that they should be entitled to cost of service rather than the area rate, or are you saying that any company that has a situation of that kind is an inefficient producer and should not receive cost of service?

BY MR. STANSFIELD:

Q. I am trying to determine really what you intend when you say the pipeline producer who could not earn a reasonable rate of return on their net investment facilities might experience increasing capital costs which would be a burden on the consumers. A. I would be happy to expand on that.

Q. This is what I am driving at. Thank you. A. What I had in mind was a situation—a possible situation where a

pipeline company under area rate would in its future exploration program spend considerable for exploration and development costs and as a result of which it didn't discover really any very good commercial prospects, and that is not an unknown situation for pipelines or independent producers. There would be no income from that or no substantial income from that production commensurate with the investment that had been made in it, and they were on an area rate basis, so they couldn't come to the Commission and say, well, we need our rates increased because we have lost money on this particular venture, but at the

[3687]

same time their net income might be reduced below a level where it would not support—properly support or completely support—the cost of capital of that particular pipeline company.

Q. Or transmission company? A. Or transmission company.

As a result its securities would not be received by investors or prospective investors as favorably as they would had they not gone into that venture. That means you may have down the road an increase in cost of capital which in turn might generate a higher rate of return for that particular pipeline company.

That is what I had in mind in my testimony.

Q. If I understand what you are saying, to the extent that this was a non-profitable and perhaps a loss operation, and as that might be reflected in the overall transmission company in its attempt to obtain capital, that the cost of capital because of that might be higher and, therefore, all the way on down to the ultimate consumer; is that correct? A. That is right. Of course in each of these situations it is a question of degree.

MR. STANSFIELD: Thank you. That is all I have.

[3687]

BY MR. TALISMAN:

Q. Referring to the assured market situation that you have your testimony on as to a pipeline producer, what is your position on the cost-of-service basis as to whether or not

[3688]

a pipeline's cost should be allowed when it discovers, let's say, a package of gas which may be sizable but because of its location it would be expensive to bring to the system in terms of it would be higher than the cost of buying gas, and let's assume in this situation that there are no alternative sales that can be made, off-system sales that are feasible. Under cost-of-service is it your position that the company should be entitled to recover its costs in that situation? A. I am assuming that the wells are capped and waiting a future market if one would develop?

Q. Yes. A. And not plugged and abandoned, but there is a valuable gas supply which cannot be marketed right now.

Q. There is a reasonable gas supply that was located far off from the system or didn't turn out to be as good as the company had hoped? A. Assuming that this venture was a prudent venture and was for the purpose of obtaining a gas supply, I certainly think that that would be includable in the cost of service. I don't know of any exclusions in situations of that kind in the Commission's experience in cost of service. They have always included the cost of whatever wells were capitalized and whatever leases were capitalized and held for future production.

Q. This would be true, let us assume, of the situation where the cost of the gas was, say, two and a half to three times

[3689]

as much on an Mcf basis as the area for that area at

which you could buy gas? A. Yes, I think that is right. Of course you would have to examine the individual circumstances, but generally that would be my position.

Q. Did you testify in the Southern Natural Gas Rate proceeding? A. Yes, I did.

Q. Isn't it true that you recommended in that proceeding that Southern be allowed the same rate of return on its production operation as its pipeline operations? A. Yes.

Q. Haven't you testified in other cases where pipeline production was involved and made the same recommendation? A. I was trying to think whether there was any other case—

Q. How about Panhandle, did you testify in that case? A. No, I did not.

—whether there was any other case in which a company claimed a higher rate of return. I don't recall right now of any other case where that was claimed. There have been other claims to get more for company production where there were the tax deductions available for statutory depletion and intangible well drilling, and that was litigated in the El Paso and United Fuel Gas cases, and I opposed that in my testimony in those

[3690]

cases.

I think Southern is the only one that flat-footedly said "We want a higher rate of return on our production properties."

Q. Based on your advocating adoption of the cost-of-service method for pipeline production, are you also advocating that the rate of return allowed on production be the same as the pipeline? A. Yes, so long as the capital comes from a common source, and whatever that cost of capital is to my mind will pretty much determine what the rate of return will be on that capital, regardless of whether it is used for the production department or the transmission department. We have gone along for 25 years' experience

[3690]

under this cost of service regulation for pipeline production, and I think in the light of this experience it has worked very well.

Q. You referred to the Commission's expressed policy for the cost-of-service method of regulation. I believe you used the Union Producing case as the principal example. A. I think that is probably a leading case on affiliate production, at least the most recent one.

Q. Isn't it true to the extent that the Commission has made any decisions to use cost-of-service rather than, say, fair field price, that those pronouncements were made in cases and perhaps influenced by the fact that the field price was substantially in excess of the cost of service if you used traditional

[3691]

cost-of-service methods?

MR. JABLON: Objection.

PRESIDING EXAMINER: The witness should answer the question.

THE WITNESS: I think it is true that in all of the pipeline producer or affiliate cases in which I testified that overall at least for that company the cost of production was less than the commodity value or fair field price that was being claimed.

BY MR. TALISMAN:

Q. And the fact that there was this substantial difference clearly was influential in terms of the outcome of those cases; is that right? A. I can't speak for the Commission on how influential that was in the final decision of the case. As far as my own philosophy on this question, I am not for cost-of-service or field price or area price rate, whichever is lower, and I am opposed to area rate, field price, or any other gimmick in lieu of cost of production, whether it is higher or lower.

Q. I gather from your statement you are opposed to area rates or fair field price or any other gimmick of that

nature, that that is your general view for independent producers as well as pipeline producers? A. No, I am not saying that. I am referring to pipeline affiliate production within the qualification which I have given

[3692]

in my testimony.

Q. In other words, you have changed your opinion on independent producers since your earlier views? A. I think it is pretty clear and maybe already on the record. Let me restate it.

As far as independent producers are concerned, my position is, and has been, that cost of service on an individual company basis is a workable and feasible method. The Commission decided we are going to do it on a composite basis. So long as that composite is based on cost of service and not market value or commodity value or average contract prices, or something, I say let's give it a try, and if it can be worked out and if it is legal, I think it may solve that problem. But so far as the pipeline companies and their affiliates, the position is as I have stated it already today.

Q. My understanding is, the thing which satisfies you for the area rate purposes for independent producers is that the area rate is based on a composite cost of service? Apparently, since it is tied to a composite cost of service, that is the major factor as far as you are concerned; it is the most important factor? A. Yes.

Q. But that wouldn't satisfy you, I gather, as far as the pipeline producers are concerned? In other words, as long as the pipeline production is tied to the composite of service, that

[3693]

wouldn't satisfy you? A. If you take the composite cost of the pipeline companies, their cost of service on their production operations and your affiliates and rolled it to-

[3693]

gether, you would have an area rate, an area rate cost anyway, and I don't know where you would come out on that.

Q. I am thinking of a composite of pipeline and independent producers. A. Well, we don't have that sort of an animal yet. Maybe we will get to it some day.

Q. But you would be opposed to that? A. I don't think it is necessary at all. I don't think it is any more logical than adding together the unit costs of transmission in Mcf per mile of all the pipelines and coming up with an average and saying that is what you are going to have to charge every place in the United States for gas.

MR. TALISMAN: That is all I have.

PRESIDING EXAMINER: Who has further questions of the witness?

Do you have any redirect, Mr. Wheatley?

MR. CHESTER: Excuse me, Mr. Examiner. I have one question, if I may.

BY MR. CHESTER:

Q. I am Charles Chester, Mobil Oil Corporation. On page 990, about two-thirds of the way down, in answer to

[3694]

question No. 16, where you make reference to the ratio of production net investment with reference to Appendix B and C producers, could you tell me, sir, whether or not the phrase or the term "production net investment," as you use it there, includes expenses for developmental dry holes and exploration expenses? A. No, I couldn't without looking in my papers. I may have that here, if you will bear with me a moment.

Yes, it does include the exploration and development investment as well as the productive well investment.

Q. Does that include developmental dry hole as well, if you know, or if your paper so indicates? A. To the extent that they were capitalized, yes.

Q. If they were not capitalized? A. I do not think they would be in that figure.

MR. CHESTER: That is all I have.

MR. WHEATLEY: I have just one question on redirect, Mr. Van Scoyoc, just to get it clear.

REDIRECT EXAMINATION

BY MR. WHEATLEY:

Q. When you prepared your testimony in this case regarding the proper regulatory treatment for pipeline produced gas, did you accept the area rate approach as a fact of life for regulation of independent producers, of course subject to whatever would be the final outcome of the Commission's area rate proceedings?

[3695]

A. Yes, it is a fact of life, and assuming the Supreme Court would affirm the Commission's opinion, then it is the law of the land, I suppose.

Q. But your recommendations regarding pipeline production are based upon that assumption or that acceptance of the area rate treatment for IP's? A. I don't think it is based upon that. I recognize that to be a fact of life, yes.

MR. WHEATLEY: No further questions.

PRESIDING EXAMINER: Mr. Ross, is it necessary for Witness Van Scoyoc to come back tomorrow because Mr. Shibley wanted some information from him?

MR. ROSS: I don't believe it will be necessary for him to return.

We would like, if possible, to have that furnished for the record.

MR. WHEATLEY: Fine. We will be pleased to do so.

PRESIDING EXAMINER: Evidently nobody else has questions of this witness. He is now excused permanently.

* * *

[Witness Corrin]
CROSS-EXAMINATION
[3717]

BY MR. WHEATLEY:

Q. In the event your costs of finding and producing gas in Louisiana and the southwest would exceed the area rate, who would sustain the loss, the consumers or the stockholders, assuming you are under area rate?

MR. LEITHEAD: May we have that question, Your Honor?

(Question read.)

MR. BROWN: Your Honor, under area rate treatment that is what we would be allowed for our gas in our cost of service. I think the answer to that question is obvious, but I won't object to it.

PRESIDING EXAMINER: Mr. Corrin, did you have occasion to think about such a situation?

THE WITNESS: As to whether the stockholder or the rate payer would bear the additional cost?

PRESIDING EXAMINER: Yes.

THE WITNESS: We would only be allowed the area rate, Your Honor, and I assume we would have to absorb the difference between the area rate and the actual cost.

BY MR. WHEATLEY:

Q. By "we," you mean the stockholders? A. The company, yes. However, if that situation exists, we will be out of South Louisiana.

[3976]

* * *

PREPARED REBUTTAL TESTIMONY OF
HERMAN G. ROSEMAN

Q. Will you give your name and address, please? A. My name is Herman G. Roseman. My office is at 80 Broad Street, New York City.

Q. What is your occupation? A. I am an economist, employed by National Economic Research Associates, Inc.

* * *

[3979]

Q. Staff witness Deutsch has proposed, at Tr. 582, that pipeline-produced new gas be priced at the prevailing area rate adjusted downward to reflect the alleged lower capital costs of pipelines. Assuming arguendo that pipelines' capital costs are lower than those of independent producers, does that mean that Staff's proposed adjustment to the area rate is appropriate? A. No. This would be unreasonable and unfair. The required return is merely one component of the industrywide new gas cost. To single out a particular group of producers as presumably having lower-than-average cost in a single component of cost is hardly fair unless it is shown that this group of producers is not above average in other cost components.

It should also be noted that if pipeline production is permitted rates below the area ceilings, this could create difficulties in acquiring undeveloped leases. Pipeline producers would ten to be forced to give royalty owners higher royalty percentages or higher lease bonuses than those given by independent producers in order to obtain undeveloped leaseholds.

In addition, under the Staff's proposal, the determination of each pipeline's rates on its own production would have to await the outcome of the individual pipeline rate

[3980]

case. The resulting extended delay in setting the rates applicable to pipeline-produced supplies of new gas would, by creating costly uncertainties, disadvantage the pipelines' exploratory activity relative to that of independent producers.

Q. Is there any reason to believe that pipeline producers have above-average costs in components other than return? A. Yes, Staff witness Deutsch has testified that this is the

[3980]

case with regard to historic cost (Tr. 619-20 and Tr. 625). The higher costs for pipeline production appear to result from relatively low depletion rates and from the purchase of relatively higher-cost developed leaseholds (Tr. 619). This evidence does not necessarily mean that pipeline producers have or will have above-average *current* (or future) costs of finding and producing new supplies of gas. But it definitely points to a real possibility that this is the case. To establish the matter conclusively would require actually doing a new-gas cost computation for pipeline producers.

* * *

[3981]

Q. In this connection, please comment on Mr. Deutsch's testimony at Tr. 627 that " . . . to the extent these higher costs reflect the purchase of developed properties, pipelines are merely making advance payments for low-risk properties for which they deserve a commensurately reduced return."

* * *

A. It is curious that Mr. Deutsch recommends adjusting the area rate to reflect the lower risk in operating such properties but does not recommend the obvious opposite adjustment to reflect the higher cost of purchasing such low-risk properties. Mr. Deutsch evidently assumes that the

[3982]

total cost of finding and producing gas is somehow reduced by the purchase of a developed property by a pipeline–i.e., by a mere transfer of ownership.

Q. Please comment on Mr. Deutsch's further statement at Tr. 627 that "There is no reason to allow pipelines additional monies to meet their increased costs for purchasing already discovered (or partially explored for) reserves which they could buy in the future at lower prices from independent producers". A. Of course, if the area ceilings were applied to pipeline-produced gas, no such "additional monies" would be paid to pipelines not would it be pos-

sible for them to buy gas from independent producers at lower prices. But "additional monies" should be allowed to the extent that the high cost of purchased properties offsets the low risk.

Q. Assume, Mr. Roseman, that pipelines have a lower cost of capital than independent producers solely by virtue of their higher debt-equity ratios. Assume, also, that in all other respects the pipelines' costs were no different from those of independent producers. Would this change any of your conclusions? A. No. I would still not recommend making a corresponding reduction in the new gas rates allowed pipeline producers. For one thing, this would simply penalize the more efficient

[3983]

procurers of capital, which runs counter to the basic concept of area pricing which rewards the more efficient producers. Second, such a rate differentiation made on the basis of differing debt ratios would seem to overlook the fact that debt ratios vary widely among independent producers and yet no such discrimination is to be applied to them. Third, the reliance on cost of capital to determine the rate of return allowed pipeline producers is in conflict with the Commission's reliance in Permian on the comparable earnings standard. The Commission used the earnings of nonintegrated oil companies as its standard, to reflect the fact that, given directionality in the search for oil and gas, the return allowed on gas would have to be comparable with the returns earned on oil production as evidenced by the returns earned by producers primarily in the business of producing oil. To impart a new principle to apply to pipeline production would seem to require a definitive showing that the economic circumstances of pipeline production differ most markedly from those of independent producers with regard to risk and directionality.

Q. Assume, Mr. Roseman, that in the past the Commission has regulated pipeline production on a company

[3983]

cost-of-service basis and has applied the rate of return applicable to the pipeline operation to the production operation as

[3984]

well. Would a comparable reasoning apply if pipelines were allowed area rates? A. No. Under area rates the business risk of pipeline production is considerably greater than with company cost of service. When it is regulated on a cost-of-service basis, the pipeline producer can be reasonably assured that it will earn the allowable rate of return, although there is never a guarantee that it will. But under area rate regulation, the return earned by any producer will depend principally on its efficiency or luck relative to that of the rest of the industry. If its costs are even moderately above the industry average, the rate of return actually earned may be significantly less than that allowed the industry. For example, if the return component in the new gas cost deemed applicable to pipeline production amounts to 3 cents per Mcf (at a 6 per cent return), then a pipeline whose finding and production costs were only a few cents more than the industry average might end up earning a zero return on its production. This result would, of course, be more unlikely under cost-of-service regulation but is not so improbable under area rate regulation.

[3985]

Q. Let us turn now to the question of Federal income taxes. At Tr. 622, Staff witness Deutsch recommends that "Tax loss spillovers from the production function should in the future, as now, be utilized to reduce the tax liability of the transmission function." If you were to assume that pipeline producers as a group generated substantial tax losses, would you join in Mr. Deutsch's recommendation?

[3986]

A. Mr. Larson's testimony shows that the evidence in this record does not support a conclusion that there are such tax losses. Even if it were true that there could be significant ostensible savings to the ultimate consumer from deducting tax losses on production from the pipeline cost of service, I believe there are compelling reasons against adjusting a pipeline's cost of service to reflect either positive or negative income tax liabilities on production activities.

Q. What are those reasons? A. First, there is the general consideration that taxes are only one element of cost. The Commission in Opinion 468 used a zero tax liability for the gas-producing industry as a whole. For pipeline producers to have tax losses would imply, therefore, that their tax cost per unit of gas produced was below the industry average. If pipeline producers have below-average costs in this single component, it is unreasonable to impose lower rates on that score without a specific finding that their other costs are not above average. Conversely, if pipeline producers have above-average costs in this component, it is unreasonable to impose higher rates without a specific finding that other costs are below average.

Second, if a company has negative income tax liabilities on its gas production, this may well be because

[3987]

(a) it is losing money on gas production or (b) it has a relatively active E&D program resulting in high E&D costs and high expensed IDC. In the first case, it is unreasonable to reduce the rates allowed pipeline producers who are already operating at a loss. In the second case, the pipeline producer would be penalized for having above-average exploratory effort, an economically nonsensical effect. In fact, those pipelines with the most exploration would have the lowest rates while those with the least exploration would enjoy the highest rates.

[3987]

Q. You have assumed in your answer that the area rate allowed the pipeline producer would be adjusted to reflect his tax liability. Suppose, however, that the total companies' tax liability, including the effect thereon of production, were simply included in the *pipeline* cost of service. Would that change your answer? A. No, since the effect would be the same in either case.

Q. Assume now that pipeline producers, on average, have a zero tax liability. Would it not be appropriate that the individual pipelines' transmission costs of service each be adjusted so that the customers of the individual pipelines benefit from or pay for the tax liabilities (negative or positive) incurred by their suppliers? A. No. As was pointed out earlier, this would tend to penalize companies which were losing money and/or had very active

[3988]

E&D programs and reward those which had relatively profitable production and/or relatively inactive E&D programs. Customers of a pipeline whose production, sold at area rates, was highly profitable might with reason wonder why this fact should require them to pay *higher* rates to the pipeline. And the pipeline with losses on its production might with equal reason wonder why this fact should occasion them to *reduce* their rates. Thus, although the suggestion in the question *appears* to satisfy requirements of fairness, its *substantive* result would be highly inequitable, as well as uneconomic.

Q. Mr. Deutsch states at Tr. 580 " . . . that the Commission should neither encourage nor discourage pipeline ownership of natural gas reserves and production." Is it your opinion, as an economist, that this would be the effect of Mr. Deutsch's modified area rate proposals? A. No. The effect would be to discourage pipelines from engaging in such activities.

* * *

[4018]

Q. In your opinion is it inherent in the nature of gas production and exploration activities that the probability of higher than average costs for any given producer is greater than the probability of lower than average costs for that producer? A. Well, what you are there asking me really comes down to a question about do I think that large producers have a different cost level than small producers, and the answer is, I don't know.

MR. FLETCHER: The answer is what? I couldn't hear you.

THE WITNESS: The answer is I don't know.

May I point out that the motion that any given producer has the equal probability of being above or below the average cost really assumes it is purely a random matter. In fact, most producers might be above average cost, or most producers might be below average cost.

* * *

[4061]

PREPARED REBUTTAL TESTIMONY OF
J. M. JOHNSON, JR. ON BEHALF OF
TENNESSEE GAS PIPELINE COMPANY,
A DIVISION OF TENNECO INC.

Q. Mr. Johnson, are you the same J. M. Johnson, Jr., who previously testified in this proceeding commencing at Tr. 741? A. Yes.

Q. Mr. Johnson, at Tr. 493, Dr. Shaffner states the following:

> "*** With regard to Phase I, in which area rates might be applied for future production, it may make sense to say that a production or exploration cost standard should be uniformly set for all pipeline produced gas, or for all pipeline produced gas in a particular area. Doing this would tend to advantage and encourage low cost production. Such pricing would place pipeline producers on an equal footing

[4061]

> among themselves and between themselves and producers and would give all the same rewards for efficiency. However, the necessary return for pipelines varies among companies. Since necessary return in large part is related to overall company functions, I would suggest that this item be continued to be separately determined for each producing pipeline and be allowed to it in place of the return component in the area rates. This would have the effect of not charging the consumer more than necessary, but gearing the return (apart from any 'incentive' return resulting from the application of area rates) to the needs of the company involved."

In your opinion, does Dr. Shaffner's statement justify separate return treatment for pipeline production?

[4062]

A. No. While the return requirements for pipeline companies may vary among companies, this does not distinguish the situation from independent producers. Obviously, the return requirements among independent producing companies may also vary. Notwithstanding this, the Commission has applied a uniform overall return in arriving at the area rates which apply to all independent producers, regardless of the individual return requirements of a particular producer. Thus, in the *Permian* decision, the Commission noted the following with respect to area ratemaking for independent producers (Opinion No. 468, p. 17):

> "True, individual returns will vary greatly, but this is as it should be, provided that profits in the *aggregate* are at a reasonable level."

Dr. Shaffner's proposal is completely inconsistent with the basic concept of area rates, which is to price the product, not the producer. As I have indicated, in the *Permian* decision (Op. 468, p. 17,) the Commission said that area rates are intended to assure that "profits in the *aggregate* are at a reasonable level," and it further emphasized that this will "give consumers the protection which the Act intended."

Q. Dr. Shaffner states at Tr. 494 that:

> "Pipeline company financing is less expensive, as a rule, than that of independent producers. To allow pipelines and producers an equivalent rate of return on their production would not give the pipelines and their stockholders 'parity,' but would give them preferential treatment."

Do you agree with this statement? A. No, I do not. Dr. Shaffner's statement, as I understand it, is predicated on the fact that pipelines, in general, have a higher proportion

[4063]

of debt in their capital structure than independent producers. But this overlooks the fact that past financing by pipelines has been devoted overwhelmingly to finance pipeline ventures, not producing ventures. Thus, it is wrong to conclude from past financing that pipelines can finance future producing ventures less expensively than IP's.

Looking to the future, I can see no reason why pipeline producers should be able to finance new producing ventures any less expensively than IP's, particularly major producers. Indeed, there are reasons why one might conclude the contrary.

Q. What are some of these reasons? A. Since independent producers have long specialized in the production business and have built up large experienced organizations to perform this function, the financial community may very well regard independent producers as having a greater know-how than pipeline producers insofar as the producing function is concerned. This is a psychological advantage which IP's may have over pipeline producers in financing producing ventures.

Furthermore, since independent producers have proportionately less debt presently outstanding than pipeline producers, they may, in fact, be in a better position to raise new debt capital to finance future producing ventures.

Q. Is there any recent evidence that IP's have been able to raise debt capital on terms competitive with pipelines?

A. Yes. Exhibit 62, which was prepared under my supervision and direction, lists recent debt issues of major producers and pipelines for comparative purposes. As can be seen from this list, the terms of recent debt issues by producers compare very favorably with pipelines.

[4064]

Q. Does the employment of debt capital in producing ventures increase the financial risk to the equity holder? A. Yes, of course, the greater the amount of leverage employed in the capitalization, the greater the risk to the equity holder. Since the equity holder is assuming a greater risk with the use of greater leverage, he expects an opportunity to earn a higher return to compensate for such added risk.

Q. In your opinion is the separation of the return element, as proposed by the Staff, fair to the pipeline producer? A. Definitely not. As I have indicated, I do not believe that pipeline producers can finance producing ventures in the future at a lower cost than IP's. But even if pipelines could finance producing ventures at a lower cost, it would clearly be unfair to select this single cost element for separate rate treatment, without also separately treating those pipeline production cost components which have been higher than the average component determined in area rates for IP's.

The evidence presented by both Mr. Bass for the Staff and Mr. Jones for the Pipeline Production Group indicates that historically the unit cost of pipeline production has exceeded the cost of production by IP's. Nevertheless, most of the pipeline producers in this proceeding are willing to be governed by the same ground rules as IP's for the future on the gamble that they will be able to produce at costs competitive with IP's. In light of past history, there surely is no sound basis for disadvantaging pipelines by allowing them a rate which is below that permitted IP's.

[4065]

Q. Is the Staff's proposed treatment of income taxes in rates for pipeline production equitable when compared with such treatment of independent producers? A. No. Under the Staff's proposal, pipeline producers would not be permitted to retain any benefits from tax deduction spillover related to production operations, whereas, under area rates, IP's are permitted to retain such tax deduction spillover benefits. These benefits can be very substantial.

This is another example of pricing the producer rather than the product, which is contrary to what was contemplated by the Commission in its *Permian* decision. Thus, while Mr. Deutsch, at Tr. 2417, sets forth a comparison of the rates to be allowed IP's and pipeline producers, the indicated 3.1¢ difference in rates does not fully disclose the difference in treatment. Obviously, drilling programs can and do vary greatly. To the extent that tax benefits are generated by the drilling program in excess of the taxable income generated by the production function, IP's can utilize such benefits as a reduction in costs associated with production of gas. On the other hand, pipeline producers would be unable to utilize the benefits as a reduction in costs associated with the production of gas, since any excess tax benefits would go to reduce pipeline cost of service and thus sales rates. The implementation of such a policy as proposed by the Staff would, in my opinion, effectively discourage pipeline ownership of natural gas reserves and production.

[4066]

Q. Mr. Johnson, at Tr. 584, Mr. Deutsch, of the Staff, states the following:

> "*** Applying area rates to pipeline production in the future would give advance notice of a general ceiling for gas."

Would the Staff's proposal give such advance notice? A. No. The Staff's proposal that the return and tax com-

ponents of the rate for pipeline production be treated on an individual pipeline basis would deny pipeline producers such advance notice. Thus, the Staff's hybrid approach deprives pipelines of the benefits of advance price notice under area rates and, at the same time, deprives pipelines of a complete individual cost treatment.

* * *

[4068]

[Witness Davis, Cross-Examination]

Q. Have you read the prepared testimony and exhibits of the FPC Staff which have been introduced into the record in this proceeding? A. Yes.

Q. Was Exhibit 57 prepared by you or under your supervision? A. Yes.

Q. Please explain Exhibit 57. A. Exhibit 57 is a summary of the production activities of the producing pipeline respondents for the years 1961-1966, inclusive. The companies are the same as those used in the FPC Staff exhibits. The source of the figures is Statistics For Interstate Natural Gas Pipeline Companies from FPC Form 2 as filed by the respective pipeline producers. A Staff witness has testified that the pipeline questionnaire data was the same or very close in value to the data reported in Form 2. Since there are relatively few respondents in this proceeding, the pertinent data is shown for each pipeline company having its own production. The production operations are classified by major production areas, namely the Gulf Coast Area, Panhandle-Hugoton Area and the Appalachian Area. Schedule 1 of Exhibit 57 shows

[4069]

there are only seven pipeline companies having their own production in the Gulf Coast Area, only four such pipeline companies in the Panhandle-Hugoton Area and one such pipeline company, El Paso Natural Gas Company, in the San Juan Area & West Texas Area. The data shows that only minor exploration has been and is being undertaken

by pipeline companies under the present method of regulation.

Q. Why do you show the production activities of the Group 1 respondents by companies and by producing areas instead of the composite grouping used by the FPC Staff? A. It is not possible to provide any worthwhile or meaningful answer in response to the issues in this proceeding without showing the extent and characteristics of the production activities of the respective pipeline companies. This is because the extent and nature of such production activity is wholly different as between companies and as between producing areas. For example, the four Panhandle-Hugoton companies produce about 2-1/2 times as much gas as the eleven Appalachian Area companies, yet the Appalachian Area companies spend about 25 times as much annually for exploration and development activities. Combining the production data for the respective areas results in unrealistic figures and fails to disclose necessary, essential facts concerning production activities of pipeline companies. The production activities of the pipeline companies disclosed by data showing such operations for each of the respective companies and areas shows there is no comparability whatever of production between such composite data and the respective pipeline companies having their own production; between such composite data nad independent producers; and between such composite data and pipeline companies having producing affiliates. No valid conclusions with respect to the production activities

of affiliates of pipeline producers can be determined from such composite figures. This is particularly true of Union's production activities.

Q. Please explain the significant differences in extent and characteristics of production activities of pipeline companies having their own production in the Gulf Coast Area. A. Of the seven pipeline companies having production in the general Gulf Coast Area, including northern Louisiana

[4070]

and eastern Texas as well as the southern areas, it is obvious from the production data that three companies, Humble Gas Transmission Company, Mississippi River Transmission Corporation and Tennessee Gas Pipeline Company are not engaged in exploration and development of gas reserves. Humble Transmission is a relatively small pipeline subsidiary of the largest major oil company and its production activity appears to be limited to the exhaustion of the largely depleted Monroe field reserves acquired with the pipeline properties. Mississippi River Transmission's production activity appears to be largely concerned with the depletion of the remaining gas reserves which it owns in the Sligo field. Tennessee Gas Pipeline Company's production activity is chiefly the production of gas reserves acquired in place. These pipeline companies are affiliates of independent producers and such pipeline production has no relation to exploration for and discovery of gas reserves for the future. Texas Eastern Transmission's production activity is also primarily related to gas reserves acquired in place but it has some exploration activities. Trunkline Gas Company has a small production activity and Consolidated Gas Supply Corporation is an Appalachian area pipeline producer which has recently engaged in certain production activities in Louisiana, as explained in their testimony. Southern Natural Gas Company is engaged in exploration and development activity on a limited scale, having 220 gas wells at December 31, 1966. Thus the production activities of pipeline companies in the Gulf Coast

[4071]

Area place emphasis and preference on gas reserves purchased in place. The exploration and development activities are minor and have not resulted in substantial volumes of new gas reserves and production.

Q. Please explain the differences in extent and characteristics of production activities of pipeline companies having their own production in the Panhandle-Hugoton Area? A.

It is a characteristic common to each of the four pipeline companies having their own production in the Panhandle-Hugoton Area, that none are engaged in exploration and development activities. Their pipeline production activities place emphasis and preference on proven gas reserves acquired prior to construction of interstate pipelines. While such production accounts for the major volume of gas produced by the pipeline respondents it is a diminishing source of gas supply. Such production operations have no relation to the exploration and development of new gas reserves required to continue service in the future.

Q. Please explain the differences in extent and characteristics of production activities of pipeline companies having their own production in the Appalachian Area? A. In the Appalachian Area, Consolidated Gas Supply Corporation has the major production operation of the respective pipeline companies. The witnesses for Consolidated have explained the extent and characteristics of Appalachian Area production, namely, that reserves and production volumes are stabilized, that the great majority of the wells are small and deliver less than 25 Mcf per day, that major independents do not produce significant quantities of gas and that such production satisfies only a minor percent of the local market. There is no comparability and no relation between production activities of pipeline companies in the Appalachian Area and pipeline companies having production in other areas or independent

[4072]

producers in other areas. The exploration and development activities of the Appalachian Area pipeline companies have no relation to the production activities required for exploration and development of substantial new gas reserves necessary to continue service in the future.

Q. Please explain the differences in extent and characteristics of production activities of pipeline companies having their own production in other areas. A. The only pipeline company having its own production in other areas is El Paso

[4072]

Natural Gas Company. The gas reserves and production of El Paso are primarily in the San Juan Basin and the extent and characteristics of El Paso production activities have been explained by its witness in this case. El Paso engaged in production activities to obtain additional quantities of gas well gas to meet its special pipeline operating problems, due to being heavily dependent for its supply upon casing-head gas produced in conjunction with oil by oil companies in the Permian Basin Area. El Paso's production operations are, for the most part, for El Paso to purchase existing wells and the underlying reserves, with overriding royalties on production retained by others. Its exploration and development activities relate largely to gas reserves purchased in place. Thus, El Paso's production operations are not comparable to the production activities of pipelines or independent producers (including affiliated producers) in other areas and its present production activities have no relation to the exploration, discovery and development of new gas reserves required to continue service in the future.

Q. Are the production activities of pipelines having their own production comparable to the production activities of the class of producers such as Union Producing Company?

[4073]

A. No. It is readily apparent from Exhibit 57 and the testimony of the witnesses for Consolidated Gas Supply Company that Appalachian Area production activities are not comparable in any respect to the production activity of Union and other independent producers in areas other than the Appalachian Area. It is readily apparent from Exhibit 57 that the Panhandle-Hugoton Area production activities of pipeline companies having production are not comparable in any respect to Union's production activity and those of other independent producers. It is readily apparent from Exhibit 57, the testimony of the witness for El Paso Natural Gas Company, and the decisions of the Commission, that the San Juan Basin production activities of El Paso are not comparable to the production activity of Union and other

independent producers. It is readily apparent from Exhibit 57 that the Gulf Coast Area production activities of pipeline companies having production are not comparable in any respect to Union's production activities and those of other independent producers, except to a certain extent, the Louisiana operations of Consolidated Gas Supply Corporation and Southern Natural Gas Company. However, the small current Gulf Coast operations of those pipeline companies even if combined with Union's operations would have no appreciable effect on Union's data shown separately herein.

Q. You previously mentioned that Exhibit 57 shows that only minor exploration for new gas reserves has been and is being undertaken by pipeline companies under the present method of regulation. Will you explain the extent of such activity as shown by Exhibit 57? A. Column (9), Schedule 1, page 1 of Exhibit 57 shows the gas reserves owned by pipeline companies at December 31, 1966. The total of such reserves is 20,500,000 M^2cf which is only about 7% of the total United States reserves of 286,500,000 M^2cf at December 31, 1965. However, the gas

[4074]

reserves owned by pipeline companies are largely the result of in-place acquisitions and the Panhandle-Hugoton reserves discovered prior to the construction of the interstate pipelines. The gas reserves other than the in-place gas reserves of Tennessee and El Paso and the Panhandle-Hugoton reserves are only about 1% of the total gas reserves. Column (8), Schedule 1, page 1 of Exhibit 57 shows the exploration and development expenses of the pipeline companies. Such expenses relate to development of proven areas as well as exploration for new gas reserves and amounted to only $19,600,000 in 1966. However, such expenses other than by Tennessee, El Paso and Appalachian Area companies are so minor in amount that the fact is evident that practically no exploration for gas reserves is being undertaken by pipeline companies. Column (1), Schedule 1,

[4074]

page 1 of Exhibit 57 shows the volumes of gas purchased by the pipeline companies having production. It is evident from columns (1), (2) and (3) that such companies must depend upon gas purchases from producers to meet the requirements of the gas consumers.

Q. Do the production activities of pipeline companies shown on Exhibit 57 indicate that they have been undertaken because exploration and development has had a "sheltered posture" under the Commission's method of rate regulation? A. No. On the contrary, the pipeline companies have gone from major production activity of exploration and development to emphasis and preference on acquired gas reserves.

The royalty expense and relation to total gas produced for the year 1966 is shown on Schedule 1, page 2 of Exhibit 57. Royalty expense at assumed one-eighth of production and wellhead value of 16¢ per Mcf would be 2¢ per Mcf of total production. When the royalty expense exceeds 2¢ per Mcf this discloses that production has been obtained by acquisition of proven

[4075]

or semi-proven gas rights through purchase, over-riding royalties, etc. Thus, the only pipeline producers with royalties of 2¢ per Mcf of gas produced or lower are Humble Gas Transmission Company, Colorado Interstate, Natural Gas Pipeline and Panhandle Eastern, being companies with reserves developed before the pipelines were constructed. The companies with royalties higher than 2¢ per Mcf of total production have proven reserves acquired by purchase and over-riding royalties. Thus, the gas customers are assured of an immediate gas supply from either type of pipeline production operation and the so-called "sheltered posture" under the cost of service method of regulation has no significance.

Q. Are the pipeline production data shown on Schedules 2 through 6 for the years 1961 through 1965 similar to pipe-

line production data for the year 1966, shown on Schedule 1 of Exhibit 57? A. Yes. The pipeline production data for the past six years show that for recent years the production activities of pipeline producers have been like the present pipeline production activities, as shown on Schedule 1 of Exhibit 57.

Q. Please explain, first, why the regulatory method proposed by the FPC Staff for pipeline producers is not appropriate for independent producers, such as Union Producing Company. A. Such regulatory method proposed by the FPC Staff is to price the gas produced at the area rate adjusted and reduced to reflect a lower rate of return equated to an individual pipeline company rate of return, income tax treatment on an individual company determination to give the tax deductions and tax loss benefits arising from production to pipeline gas customers, and a credit for liquids produced on an individual company determination.

[4076]

This method would necessarily result in rates and prices to independent producers such as Union lower than the rates and prices received by other independent producers. Under such unfair and unreasonable discrimination, such class of production operations would not be practical, prudent or economically feasible.

Q. Explain why, under a Commission regulatory policy resulting in lower rates to Union than other independent producers, production operations such as Union's would not be practical. A. The purpose of exploration and development activities is to discover areas of favorable potential new production and to acquire leasehold rights to obtain such production. Production rights are obtained and held by bonus payments, farm-outs, royalties and over-riding royalties. The amounts of such payments are directly related to the potential production gross revenues.
Thus, since the gross revenue from the class of producers such as Union would be lower than would be obtained by other producers, that class could not successfully negotiate

[4076]

for the leases it deemed desirable. Competition for favorable prospects is ever increasing as areas considered most productive are pre-empted through leasing arrangements. Without lease rights to obtain production, all other exploration and development activities would be a useless effort and it obviously would be impractical and imprudent to even start further production operations under such regulatory conditions.

Q. Explain why, under the regulatory method proposed by the FPC Staff for pipeline producers, Union's future production operations would not be economically feasible aside from the leasing and other operational impracticalities of such method?

[4077]

A. Union, being wholly engaged in exploration, development and production activities has and will continue to have the same financial needs and risks of other independent producers. Union, like other oil and gas producers, has been and will continue to be faced with the constant necessity of plowing back into the business a substantial part of its revenue above depletion and depreciation accruals, which funds must come out of its earnings. Union needs as much return as other producers to replenish the exhaustion of its mineral reserves and maintain production. It is not economically feasible for the class of producers such as Union to undertake and carry on the same exploration, development and production activities at lower prices and subject to regulated earnings fixed at a lower level than is economically feasible and allowed to provide a reasonable incentive to other producers.

Q. Is there any reason or justification for a lower rate of return for the class of producers such as Union than the rate of return for other producers? A. No, there is not. Under the standard that a fair rate of return must be commensurate with returns on investments having corresponding risks it is immediately apparent that the class of producers such as Union requires a rate of return comparable to other

producers. In the oil and gas industry capital can be attracted only if the return is sufficient to enable the companies to service the debt and pay dividends on the stock, after the plow-back of internally generated cash, including a substantial portion of the return, required to replace and replenish the wasting assets currently consumed and to continue production in the future.

The class of producers such as Union operate as a separate corporate entity. None of Union's costs of operation, exploration and development

[4078]

are, or ever have been, reflected in or are, or ever have been, borne by any other company with which it is affiliated. Union has a total capitalization of $182,800,000 at December 31, 1966 which is composed of $35,500,000 of debt and $147,300,000 of equity. This capitalization ratio of 20% debt and 80% equity is comparable to independent producers generally. Each separate operation and enterprise must stand on its own feet and, unless it is proposed that the class of producer such as Union be involuntarily liquidated, a fair rate of return, as with other independent producers, must provide cash sufficient to continue exploration and development and attract external investment of capital to the extent required.

Therefore, it makes no difference whether the source of outside cash investment be a parent or a stranger. Each must have a reasonable basis upon which to justify the investment of funds. The investment of capital received from sale of securities to the public in an affiliated producing company at a rate of return prescribed by the Commission that is lower than is available from a comparable non-affiliated producing company would not be reasonable or justifiable to present or prospective stockholders.

Q. Will you please illustrate why the capital investment needed for continued production of a wasting asset, such as natural gas, requires a higher return than the capital

[4078]

investment in non-wasting assets, such as telephone properties, electric properties, or gas transmission and distribution properties? A. Yes. For such illustration I will use the amounts in Opinion 468, 34 FPC 192. The Commission found that a price of 16.43¢ per Mcf would be sufficient to provide depletion and depreciation expense of 3.95¢ per Mcf and return of 5.56¢ per Mcf. Those are the non-cash items in the cost of

[4079]

service. Revenues to cover these costs are the source of cash required to service the debt, pay dividends on the stock and replenish the remaining gas reserve, which is being exhausted by production.

The costs of developing new reserves and drilling new wells are greater than past costs for such development. The actual experience of Union Producing Company for the 12-year period 1954-1965 inclusive, has been that cash generated and available from the non-cash items of depreciation, depletion and abandoned leases has been $126,700,000 and cash required for capital expenditures needed to replenish and maintain the reserves was $202,200,000. The remaining reserves were less at the end of 1965 than in 1954 and during the period Union produced 64% of its gas reserves, 74% of its condensate reserves and 110% of its oil reserves as of the beginning of the period.

Thus, such independent producers would have cash from depreciation, depletion, amortization and return of 9.51¢ per Mcf and would have to plow back at least 6.60¢ per Mcf (3.95¢ x 1-2/3) to maintain the present production and revenues. This leaves cash of 2.91¢ per Mcf for the return, which is 6.3% rate of return on the invested capital of 46.33¢ per Mcf.

The 12% rate of return used in Opinion No. 468 is not the rate of return available to equity owners. No more than 6.3% rate of return could be paid on their investment. The 12% rate of return is what would be available if the re-

maining reserves and producing wells should turn out to be inexhaustible.

Q. Will you please illustrate the fallacy of the FPC Staff position that independent producers affiliated with pipeline companies could be less

[4080]

expensively financed by issuance of 61% long-term debt, 8.5% preferred stock and have only 30.5% common equity?
A. Using the Commission's figures referred to above, but with a capital structure and cost of money as shown on Appendix A, page 1 to the prepared testimony of Staff Witness Shaffner, with the overall return at 6.5% the capital costs per Mcf would be as follows:

	Capital Ratio	Investment Per Mcf 4.212¢ x 11 Years	Computed Rate of Return	Cost Per Mcf
Debt	61.0%	28.26¢	4.75%	1.34¢
Preferred	8.5%	3.94¢	4.97%	.20¢
Common	30.5%	14.13¢	10.43%	1.47¢
	100.0%	46.33¢	6.50%	3.01¢

The producers would have cash available from depreciation, depletion and amortization accruals of 3.95¢ per Mcf and cash from return on equity of 1.47¢ per Mcf, or total cash available of 5.42¢ per Mcf, but would have to plow back 6.60¢ per Mcf to continue production. The producing company would be left with a constant cash deficiency of 1.18¢ per Mcf of gas produced. This would be disastrous.

It is unsound and fallacious to assume that a producer of a wasting asset could be less expensively financed by using the relatively high debt ratios and fixed costs applicable to pipeline companies. It is obvious that substantial debt and

[4080]

preferred stock would cause substantial fixed cash payments out of the return allowance; obvious that gas producers are faced with the constant necessity of plowing back into their business a substantial part of their revenue above depreciation and depletion accruals; and obvious that the gas reserves currently being produced and consumed must be replaced to continue service in the future. Such financing for producers, instead of being geared to the

[4081]

needs of the company involved, as claimed by the Staff witness, is directly contrary to the needs of the company involved.

Q. Appendix A, page 1 to the prepared testimony of Staff Witness Shaffner shows a computed allowance on common equity for pipeline companies ranging from 9.61% to 6.25% overall rate of return to 41.57% at 16% rate of return. Will you state the comparable cash return available for common equity of an affiliated independent producer using the Staff assumptions of capital ratios, capital costs and rates of return with the costs found in Opinion No. 468, 34 FPC 192? A. Yes. The capital cost found by the Commission is 46.33¢ per Mcf. The staff assumption of 30.5% equity results in equity capital of 14.13¢ per Mcf, as shown above. The capital required to replace the gas reserves being exhausted and drill new wells of 6.60¢ per Mcf is 2.65¢ per Mcf over the depreciation, depletion and amortization accrual of 3.95¢ per Mcf. Such excess of 2.65¢ per Mcf must come from the return allowance for common equity. The 2.65¢ per Mcf out of the return allowance for equity is 18.75% of the equity capital of 14.13¢ per Mcf.

Appendix A, page 1, as revised to show the maximum cash available for return on common equity of an independent producer such as Union Producing Company, is as follows:

Assumed Return–%	Funds Available for Return on Equity–%
6.25%	– 9.14% (cash deficiency)
6.50	– 8.32 (cash deficiency)
9.50	1.51
10.50	4.79
12.00	9.74
16.00	22.82

Q. Will you state the comparable cash return available for common equity of an independent producer using the same assumptions shown on page 2, Appendix A to the prepared testimony of the Staff witness?

[4082]

A. Yes. The Staff assumption of 85.6% common equity results in equity capital of 39.66¢ per Mcf of which 2.65¢ per Mcf or 6.68% is cash required in excess of depreciation and depletion accruals to maintain gas reserves and drill new wells to continue the same volume of production. Appendix A, page 2 as revised to show the maximum cash available for return on common equity, is as follows:

Assumed Return–%	Funds Available for Return on Equity–%
8.00%	1.99%
8.50	2.57
9.00	3.16
9.50	3.74
10.00	4.32
10.50	4.91
11.00	5.49
11.50	6.08
12.00	6.66
16.00	9.32

[4082]

It will be noted that the above returns on common equity result from the low cost of debt money assumed as of 1962, being 4.75% debt cost for pipeline companies and 4.02% debt cost for independent producers. Such assumed costs are unrealistic for more recent periods. The higher fixed charges for debt would further reduce the return available for common equity.

Q. Are there other reasons why the assumption of substantial debt and preferred stock financing for affiliated independent producers is unrealistic? A. Yes. Debt and preferred stock capital borrowed for a wasting asset must be repaid in a relatively short period of time. On the Commission's basis of a 20-year life for the gas reserves and gas wells, probably 15-year annual sinking fund provisions would be required, or even less if oil wells were involved. The producer would have to borrow money to

[4083]

repay borrowed money. It would be foolish to get into such a cash bind, which would become progressively worse due to the sinking fund period being shorter than the revenue producing period. This causes increasing fixed interest and sinking fund cash requirements when the cash requirements needed to continue production are also increasing.

Q. Are there other reasons, in addition to the prohibitive operating and financial problems you have mentioned, why under the regulatory method proposed by the FPC Staff, future operations of independent producers such as Union Producing Company would not be economically feasible? A. Yes. Such method is contrary to justifiable business considerations. It is unsound in this respect because, before gas reserves can be discovered and production developed, such producers would necessarily have to expect to spend large sums for geological and geophysical surveys, incur expenses of a land and lease department and production department, pay for leases, pay delay rentals, dry hole costs and other expenses over a period of years. The FPC

Staff method provides that the only regulated revenue such producers would be entitled to receive to pay such expenses would be from current gas produced during such exploration and development period. Thus, it follows that the losses from exploration and development would have to be paid by the stockholders. The costs and losses from such exploration and development activities would not be allowed as a charge to the rate payers and could not be recouped under the FPC Staff's proposed regulatory policy. Even if and when substantial new gas reserves are discovered and gas is produced then the producer would be allowed to charge only current costs but could not recoup any of its past expenses.

The expenditure of large sums of stockholder's capital under conditions that preclude any recoupment of losses and, even in the event of

[4084]

successful discovery and production, then limitation of price to a ceiling fixed by a pipeline rate of return and the investment and production expense average of the successful independent producers only, would be an unsound and impractical business venture.

Q. Are there other reasons why, under the regulatory method proposed by the FPC Staff, future operations of independent producers such as Union Producing Company, would not be a sound or realistic business venture? A. Yes, and another reason which should be pointed out why such method is contrary to justifiable business considerations arises from the proposed regulatory treatment of income taxes and tax losses. The proposed policy is that the tax deductions and losses from the exploration, development and production activities of an independent producer having corporate affiliation with a pipeline company would be given to the pipeline company's rate payers in the form of reduced income taxes in the pipeline cost of service and lower rates to the gas customers. This rate reduction to

[4084]

gas customers would occur even when none of the costs giving rise to such tax deductions and losses are reflected in the pipeline cost of service and even when the pipeline company taxable income from non-regulated activities is equal to or in excess of such tax deductions and losses.

With a 48% Federal income tax rate such regulatory treatment almost doubles the cost effect of tax losses from exploration and development activities of independent producers affiliated with a pipeline company. This treatment would eliminate justification for engaging in exploration activities requiring the expenditure of large amounts of corporate funds and tax losses during the development period.

Q. Please explain, next, why the regulatory method proposed by the FPC Staff for pipeline producers is not administratively feasible for the class of independent producers such as Union Producing Company.

[4085]

A. The FPC Staff erroneously assumes that its proposed regulatory method "would aid in handling the administrative problems of regulation common to pipeline production as well as to other production. (e.g., collection of production cost data classifications)" On the contrary, the FPC Staff method would create extensive and confusing administrative and regulatory problems and is unsuited to orderly regulation in every aspect. This is because the FPC Staff method proposes a mixture of average costs and individual company costs. For example, the Staff proposes to use the Commission's determination of national average finding and production costs modified to apply the Commission's policy in pipeline rate cases of using the actual taxes which would be paid on the basis of the return on rate base in deriving a Federal income tax expense.

The prepared testimony of the Staff witness states (Tr. 623):

> "Since return and tax expense are interrelated, I think these items should be determined with regard to the individual company."

However, the FPC Staff's proposed method is *not* to determine, or reflect in rates, the return applicable to the individual company. The individual company return would be the product of the individual company rate base and the individual company rate of return. The return under the Staff's proposed method is computed by a formula of the national average depletion, depreciation and amortization expense per Mcf of gas produced, times 11, times the individual company rate of return. The result of such computation does not have any relation to or even a remote resemblance to the individual company return computed at the same rate of return. This inconsistency in the computation of return on the hypotehtical national average rate base makes the Staff's proposal to

[4086]

reflect taxes actually paid based on each individual company return and tax deductions, in accordance with Commission policy in pipeline rate cases, so inconsistent as to be impossible and, of course, not administratively feasible.

Q. Will you please explain other specific reasons why the Staff's proposed method with respect to Federal income tax allowance is not administratively feasible for independent producers such as Union Producing Company? A. The computation of Federal income tax allowance on an individual cost of service basis requires a determination of the individual company gas tax deductions related to the return on the individual company gas base.

Tax deductions are the actual operating and maintenance expenses, royalties, exploration and development costs, property taxes, miscellaneous State and Federal taxes, depreciation of certain property investment on either straight line or liberalized depreciation method, depletion on cost, 27-1/2% of lease gross income, and 50% of lease net income, interest expense, intangible drilling costs, capital gain or losses, general and administrative expense and other allowable deductions. In order to determine the income tax

[4086]

deductions applicable to gas cost of service the Commission would have to determine a proper cost for each of the cost items for a test period and make adjustments for known changes in the future for each individual company. Then it would be necessary to separate and allocate each item of joint cost between gas, condensate, oil and other non-utility activities. In other words, the Commission would have to add to its national average rate determination a complete cost of service rate case for each individual company. The Commission has found that this procedure is not sensible, or even workable, for the

[4087]

numerous reasons set forth in its Opinion No. 338, Phillips Petroleum Company. Furthermore, in order to apply the Staff's method, the Commission would have to determine the actual investment, reasonable reserves for depreciation, depletion and amortization and working capital for a test period, make adjustments for known changes in the future for each individual company, and then make the separations and allocations of the rate base items between gas, oil, condensate and other non-utility activities, necessarily by procedures which are not sensible, or even workable. Such process for each company would be necessary to determine a gas rate base to which the recommended rate of return would be applied in order to compute the individual company return applicable to gas operations.

Whatever the end result achieved by the Staff's proposed method, it would be meaningless because the amount of return component to be used for tax computations would not be the proposed return component and the computed income tax amount would not be the taxes actually paid or to be paid.

Q. Would it be sensible, or even workable, to disregard the individual company return and compute income taxes called "paid" on gas operations based on the return computed by the FPC Staff's formula? A. No, that procedure

also would not be sensible, or even workable. Such procedure would result in more complexities, inconsistencies and arbitrary assumptions than using the return on the individual company rate base, as adjusted and arbitrarily allocated to gas operations. All revenue and expenses are interrelated in the determination of taxable income, or loss, and the amount of income tax applicable to gas operations of an individual company cannot be determined except upon the determination of the gas revenues and gas tax deducations of the particular

[4088]

company. Since a return allowance computed by the FPC Staff's proposed formula would be completely different from the actual return earned by the individual companies that figure would not and could not enter into a determination of taxes actually paid or to be paid.

Actual or projected gross revenue could not be used in the determination of the Federal income tax allowance as proposed, since obviously, under regulation of prices, the sole purpose of making the Federal income tax computation is to determine the gas prices and revenues. Therefore, the regulated gas prices are unknown and regulated gas revenue is unknown. Since the regulated price is not known, the royalty expense and other tax deductions dependent upon revenues are unknown amounts. Percentage depletion tax deduction would be 27-1/2% of the unknown lease gross income, not to exceed 50% of the unknown lease net income. Therefore, the tax deductions for royalties and percentage depletion could not be determined for purpose of computing the amount of Federal income tax allowance for regulatory purposes.

Of course, the determination of gas tax deductions from gas revenues or gas return involves all of the processes, allocations and arbitrary assumptions required to separate the various items of gas costs from other activities for a test period, adjusted for known changes.

[4088]

However, the proposal that the Commission should, or could determine taxes actually paid when revenues, return, royalties, percentage depletion, etc. are unknown amounts is beyond the bounds of reasonable regulatory procedure.

* * *

[4094]

Rebuttal Testimony of Albert F. Bass

Q. Would you please state your name? A. Albert F. Bass.

Q. Are you the same Albert F. Bass whose previous direct testimony in this proceeding appears at 8(1)/533-547? A. Yes.

* * *

[4097]

Q. What is your other purpose related to schedules numbered 1 through 6?

* * *

[4098]

Witness Peck at 8(1)/695 (revised at 24/2669) quartiles unit cost data, supplied by witness Jones, for the independent producers, the pipeline affiliates and pipeline producers and states:

> While the pipeline producers do not match exactly the distribution of the independent producers, the data demonstrates that all three classes of producers are characterized by a substantial disparity among the individual company unit costs for the production of natural gas.

But witness Peck's data for the pipeline producers do not show an even distribution; the data tend to group at the two extremes. That is, most of the pipeline producers are either in the lowest or the highest cost quartiles. Rather than supporting the pipeline group's thesis of similarity,

these groupings support the contention that there are two general groupings of pipeline producers: low cost pipelines that acquired low cost gas reserves relatively early in the history of the gas pipeline industry and pipelines that acquired their reserves more recently and at relatively higher costs.

* * *

[4100]

It also reveals that the producing pipeline groups' expenditures charged to asset accounts for producing leases ratios were well over twice the ratio of the other producer group. Schedule 2 of Exhibit No. 54 (AFB-2) reveals that the high composite pipeline group ratios shown in Exhibit No. 5, Schedule 3, are largely influenced by the high ratios and large producing lease purchases of Tennessee, Texas Eastern, and El Paso. Panhandle Eastern Pipeline Company's ratio is much lower than these three companies' ratios and Colorado Interstate's ratio is zero. Many producing affiliates including Tenneco Oil Company, Anadarko Production Company, and Colorado Oil and Gas Company have high ratios. These high ratios may well be indicative of their acquisition of properties from their related pipeline companies.

* * *

[4124]

* * *

Q. Do you agree with the pipeline production group that industry average finding and production costs should be allowed as the cost per Mcf of gas delivered from a pipelines' own production properties to its transmission system in a pipeline company cost of service determination? A. Yes. Staff does agree that this is the most desirable form of regulating "future" pipeline produced gas. The reasons for this are stated by staff witness Deutsch in his direct testimony. But what Schedule 11 indicates is that in the years since World War II there has been a tremendous

[4124]

growth in the natural gas pipeline industry. Moreover, as my Schedule 10 indicates, the 1966 overall earnings reported to the Commission by these companies are greater than those allowed on the jurisdictional

[4125]

rate base in the companies' last litigated rate cases. And even in the case of their well mouth plant, the producing pipeline companies as a group show a sizable increase in their investment. Such growth patterns on the part of the producing pipelines and by the industry should eliminate any question that in order to protect the health of the industry the pipeline producers need any "incentives" in addition to those which would otherwise be allowed. Rather, given this continued growth of the plant and investment of these companies, the question is not one of a need for reinvigoration, but rather one of what is the best mode of regulation to apply to pipeline production.

Q. Would you relate Schedule 11 to witness Peck's statement at 8(1)/705:5-8? A. Yes. Witness Peck there states that, "The relevant inquiry is whether the production activities of the pipeline companies have retained their relative importance in comparison with other classes of producers." He goes on to state that they have not. This decline is attributed to the effects of regulation. Schedule 11 shows that not only have total gas plant and transmission

[4126]

plant of the producing pipeline companies grown at a fast rate; investment in well mouth plant has grown as well. Witness Peck at 8(1)/687:1-688:12 attributes the "downward overall trend" for pipeline production solely to the Commission's cost-of-service regulation. At 29/3262:24-3264:6, witness Peck reaffirms this conclusion, rejecting the hypothesis "that a capital shortage might explain the decline." However, rather than support the pipeline production group's conclusions, an examination of the growth

[4169]

of the producing pipeline companies and their pipeline plant indicates that the growth of their well mouth properties after 1950 has been roughly commensurate with their growth in total gas plant. However, between the Years 1944-1950 the well mouth plant investment of the pipelines was relatively stable. This was the period for which witnesses Shaffner and Duetsch both testified that the pipeline companies began their initial surges of great growth; it was also a period during which independent producers had available large amounts of uncommitted gas reserves for which there was no ready market and which the independent producers were ready to sell

[4127]

at attractively low prices. Given the availability of these low cost supplies and the commensurate need for greatly expanded transmission resources to get these supplies to market, I question whether it can be expected that pipeline companies would have or should have focused their attention on finding additional reserves of their own rather than on purchasing them. In such a situation, I agree with witness Shaffner and Deutsch that it is not surprising that the pipeline companies relied on purchased reserves to support their transmission expansions.

* * *

[4169]

PROPOSED REBUTTAL TESTIMONY OF KENNETH L. SMITH

Q. Please state your name and residence. A. Kenneth L. Smith, Bethesda, Maryland.

Q. Have you previously testified in this proceeding? A. Yes.

Q. Have you been requested to present rebuttal testimony and exhibits on behalf of the Municipal Gas Group of Intervenors in this proceeding? A. Yes.

Q. What is the purpose, in general, of your proposed re-

[4169]

buttal evidence? A. To rebut certain portions of the Staff's testimony relating to the alleged administrative and consumer advantages of its proposed area rate valuation of pipeline produced gas and the proposed utilization of production department tax benefits under such area rate procedure; and to supply references and information to identify or clarify historical data included in the record.

Q. In support of his recommendation of area rates for Phase I of this proceeding, Mr. Deutsch testified on page 583 of

[4170]

the record, beginning at line 18, that "the application of area rates to pipeline production would aid in handling the administrative problems of regulation common to pipeline production as well as to other production." Have you formed an opinion as to whether the Staff's recommendation, if adopted by the Commission, would in fact aid in handling administrative problems of regulation common to the various classes of gas producers? A. Yes.

Q. Did you conclude that the Staff's recommended application of area rates to pipeline production would aid or hinder in the handling of administrative problems of regulation? A. I believe that any advantages to administration are largely illusory and that the Staff proposals would actually hinder and unnecessarily burden administration.

Q. Does your testimony appearing at page 964 of the transcript indicate that you occupied a position on the Commission's Staff as either an assistant division chief or an assistant bureau chief during some nine years or so out of the sixteen years you were employed by the Commission? A. Yes and I would point out that the period from 1941 to 1945 when I was Assistant Chief Accountant with responsibility for supervising the accounting studies made by the Staff in the larger and more difficult natural gas rate cases, was the period in which the Commission decided a number of the important, land mark cases which established,

with court approval, the legality, practicability, and workability of rate regulation of natural

[4171]

gas companies on the net investment basis. I will state also that the period from 1956 to 1962, when I was an Assistant Bureau Chief with responsibility for all investigations, cost studies and cost allocations undertaken for rate cases, was one in which the Staff made extensive studies into the costs of a large number of independent producers, was devising the format for independent producer area rate cases and at the same time was reviewing and evaluating its procedures and practices in order that the information required by the Staff and Commission in pipeline rate cases could be obtained with substantially reduced reliance on government personnel.

Q. Does your testimony mean that for a total of some nine years the positions you occupied on the Commission's Staff involved top level responsibility in connection with obtaining, interpreting, organizing and presenting data required in connection with the determination of just and reasonable rates of the companies regulated? A. Yes, it does. I would mention, of course, that I was subject to Commission policy and general supervision of superior officers in the bureau. These limitations were not so restrictive, however, that opportunities for the exercise of individual judgment on my part and utilization of my individual technical and administrative skills were lacking. It is also a fact that my activities in top level positions while employed by the Commission were concerned principally with rate regulation under the

[4172]

Natural Gas Act.

Q. During the period starting in 1956 until 1962, when you served successively as Assistant Chief of the Bureau of Rates and Gas Certificates and of the Bureau of Natural Gas,

[4172]

did you have occasion to consider or deal with the question of whether regulation on a cost basis of pipeline and affiliated production should be abandoned, either in whole or in part, in favor of some other approach? A. Not that I recall. At least I am certain that this matter received no major attention or emphasis at my level of responsibility during that period. By this I do not mean that I necessarily felt that the matter of proposals for change had been forever eliminated as a result of the court decision in the *City of Detroit* case in 1955. It was a problem, however, which I was not confronted with at the time I served as Assistant Bureau Chief.

Q. Did you have any actual experience while you were employed by the Commission in rate cases in which evidence was introduced as to the claimed commodity value or field price of pipeline produced gas? A. Yes, prior to becoming Assistant Bureau Chief.

Q. What were these cases, and briefly what was the situation? A. In 1954 and 1955 I supervised audit activities and preparation of the accounting exhibits presented by the Staff in a case involving a rate increase filed by Natural Gas Pipeline Company of America in Docket No. G-3123. Natural contended initially

[4173]

that it should be allowed the average weighted field value for its own production in the West Panhandle Field of Texas, in lieu of such production being costed on the traditional rate base approach, 19 FPC 1,003. Following the uncertainties generated by the decision of the Court of Appeals in *Memphis Light, Gass and Water Division v. F.P.C.* 250 F.2d 402 (CADC), cert. granted, 355 U.S. 938, and the resolution of the field value issue in *City of Detroit v. F.P.C.* 230 F.2d 810, cert. denied, 352 U.S. 829, Natural negotiated a proposed settlement on a cost of service basis in Docket No. G-3123, as well as in another rate increase filed in Docket No. G-12157 (19 FPC 1004), which settlement the Com-

mission approved in substance, subject to certain terms and conditions, 19 FPC 1008.

I also participated in a supervisory capacity during the period around 1954 and 1955 in the Staff's preparation of evidence presented in hearings on rate increased filed by Colorado Interstate Gas Company in Dockets G-2260 and G-2576, in which that company claimed it should be allowed a field price in lieu of cost, for its own produced gas. The Commission agreed with the Presiding Examiner that the evidence did not "show that Colorado Interstate should be allowed more than cost for the production of its own gas computed under the traditional rate base method", 19 FPC 1017.

In a much earlier rate case involving Colorado Interstate (Docket G-124) in which I testified and had supervisory responsi-

[4174]

bilities in connection with the Staff examination of the Companies' books and records, the producing affiliate of Colorado Interstate, namely, Canadian River Gas Company, offered evidence of a commodity value of its natural gas production which would give a much higher value than cost to the production phase of Canadian River's business. *Colorado Interstate Gas Company v. Federal Power Commission, et al.* (Sup. Court) 58 PUR (NS) 65, 81. As is well known the Supreme Court refused to hold that the Commission erred in including the production properties of Colorado Interstate (then owned by its affiliate, Canadian River) in the rate base at "actual legitimate cost." (*Ibid.*)

Q. What experience did you have as an employee of the Commission pertaining to the treatment of gas produced by affiliates of pipeline companies in rate determinations? A. I have already indicated my role in the early rate proceeding under Docket No. G-124 against Colorado Interstate Gas Company and Canadian River Gas Company which was the affiliated producing arm of Colorado Interstate and also

transported gas as an incident to its producing function so that such gas would be delivered to Colorado Interstate outside of the State of Texas.

One of my first assignments after being promoted to the position of Assistant Chief Accountant in 1941 was to organize and direct the accounting phases of a field investigation of United Gas Pipe Line Company in Docket No.G-148 and coordinate the accounting work with that of Staff Engineers assigned to such investigation. This investigation involved among other

[4175]

things, the checking of original cost of plant acquired by United which had been owned by some 35 or 40 predecessor companies. This case was ultimately settled without a hearing. 3 FPC 402. During the investigation the amount paid by United to its affiliate, Union Producing Company, for purchased gas was scrutinized although a complete cost study of Union was not undertaken at that time. The necessity of being satisfied as to the reasonableness of amounts paid by United to its affiliate, Union, for purchased gas was regarded by the Staff as in keeping with the determination of the Commission in the *Columbian Fuel Corporation* case on June 29, 1940, 2 FPC 200,207. The concurring opinion in the United Gas Pipe Line settlement shows that "the reasonableness of charges paid by this company (United) to an affiliate for gas purchased" was one of the determinations with which the Commission was concerned. 3 FPC 407.

During this same era the Commission had used its investigative powers in connection with determing whether Mississippi River Fuel Corporation was paying unreasonable charges to affiliated gas suppliers. 2 FPC 826, 827.

After the *Phillips* decision in the Supreme Court in 1954, affiliated producers were required to file rate schedules and, in this limited context, have been treated on a par with independent producers. During the period from 1956 to 1962

when I served as an assistant bureau chief, I did not regard the classification of affiliated producers for rate filing purposes as

[41-76]

having any substantive effect on the basic regulatory principles which had been applied for approximately 15 years prior to 1954. The regulatory mechanics had been changed, the Commission's use of its jurisdictional authority may have been widened, and the timing and form of any action relating to the rates charged to a pipeline by an affiliated producer might be subject to change, but I regarded the affiliated producer, particularly where it functioned as the producing arm of its pipeline affiliate, as being subject to the same basic regulatory policy as the production department of a pipeline company.

Q. Mr. Deutsch indicated in his testimony at page 2506 of the transcript as well as elsewhere that he recommends retention of the Uniform System of Accounts for pipeline companies having a production department and would have no recommeded revisions to present accounting requirements except for segregation of investment and expenses on new properties acquired after the effective cut off date. Does this correctly state your understanding of Mr. Deutsch's testimony? A. Yes, in general. I would point out further in this connection that he proposed no change in the Uniform System of Accounts for pipeline companies, according to his testimony on the last few lines of page 2466 of the transcript, and that he would expect to be able, however, to make the numerous separations and allocations of cost which he mentioned in his testimony on page 2508 of the transcript.

[4177]

Q. In your opinion, would these proposals result in a lessening of the Commission's administrative burdens? A. No.

[4177]

Q. Does your answer mean that you disagree with the answer which Mr. Deutsch gave at page 2505 of the transcript, lines 3 and 4, to the effect that subjecting pipeline producers to area rates would lessen the Commission's administrative burden of determining a cost for pipeline produced gas? A. Yes, it does. Mr. Deutsch's proposals would actually increase the Commission's administrative burden rather than lessen it.

Q. Why is that so? A. Mr. Deutsch's testimony at page 2508 lists a number of items which would have to be excluded and allocated in computing the transmission cost of service and rate base of a pipeline producer which would be subject to an area rate valuation for all or part of its own produced gas. What Mr. Deutsch described in that testimony would not be a one-shot operation. It would have to be repeated, and should be done meticulously, each time the pipeline company's rates were changed. This detailed carving out of production costs, which must be done when an area rate valuation of pipeline produced gas is used, does not have to be done in a rate revision undertaken under the Commission's traditional cost of service regulation. Contrary to the simplicity implied in Mr. Deutsch's testimony at page 2508, this cost segregation, involving complex and controversial alloca-

[4178]

tion problems, cannot be brushed aside lightly with the observation made by Mr. Deutsch that such problems are "not insurmountable."

Q. Based on your accounting experience of nearly 40 years since you became a CPA, which includes your regulatory experience, do you consider the separation and attribution of costs of a pipeline company applicable to its own produced gas to be a relatively simple or routine procedure? A. No, it is neither relatively simple nor routine. Moreover, unless procedures governing such separation and attribution are carefully defined and prescribed in a proper manner, the results obtained by different accountants or

engineers could be expected to vary substantially. The principal reason for this is that nearly all of the costs of production at the specified or defined point of separation would of necessity be allocated costs. This would certainly be true with respect to the present Uniform System of Accounts under which, for example, operation and maintenance expenses are functionalized only partially to the extent that would be required if the costs applicable to pipeline production are to be carved out fairly and set aside from the cost of transmission and any portion of gathering cost which would be recoverable from a pipeline's customers under traditional cost of service principles. The point is that there are no ready-made non controversial allocation procedures which can be drawn upon to get quick or easy

[4179]

solutions to these problems. Administration of the Commission could not possibly be facilitated when cost accounting complexities and controversy are added to each pipeline rate case. Developing suitable procedures for allocation of taxes and depreciation would be even more elusive than for operation and maintenance expenses. It is obvious, of course, that these problems would be compounded if some of a pipeline's produced gas were regulated on a cost basis and some were subject to area rate valuation. Accounting for produced gas by "vintages," as apparently would be necessary under the staff proposal, constitutes a further complication and would be an added burden on everyone concerned.

Q. In your opinion, could the standards of accounting for pipeline production which have been evolved and developed under the Uniform System of Accounts be preserved and maintained if such production or some part of it were valued on the basis of area rates? A. No, these important gains in regulatory procedures would be lost—if not immediately, by gradual erosion.

Q. Why would such disintegration of accounting standards occur? A. If pipelines are given so-called "parity," or

[4179]

area rate treatment in valuing their own production, either along the lines advocated by the Pipeline Production Group, or as proposed by the Staff, they would naturally demand the same freedom that independent producers enjoy under Federal Power Commission

[4180]

regulation to determine their own methods and policies of accounting for their leases and production which were subject to area rate valuation. Absent the ability to do this if ownership of leases and reserves were retained by the pipeline company, the natural consequence or tendency would be for any reserves subject to area rate treatment to be owned by affiliates rather than by pipelines directly. A recent development underscores this. A pipeline producer which was confronted with enforced compliance with the standards of the Uniform System of Accounts with respect to its production properties has proposed a transfer of

see Gas Pipeline Company, a Division of Tenneco, Inc., Docket No. RP67-22, "Order Prescribing Procedure and Setting Prehearing Conference," issued October 27, 1967. At the same time the affiliate, Tenneco Oil Company, who would be the recipient of the transferred reserves, was attempting to show in this proceeding (Docket No. RP66-24) that it should be regulated as an independent producer rather than as a pipeline affiliate. This might seem to be merely an isolated instance, but it is illustrative of what is likely to happen at any time so long as a company can select an alternative accounting standard which better suits its purposes. According to Gresham's Law, inferior money invariably displaces good money in circulation. The result when alternative accounting procedures are available is somewhat parallel. The choice made will be that

[4181]

which best suits the company's purposes, even if it is inherently inferior. There is no more important single facet of

the regulatory process, however, than maintaining and enforcing accounting systems which augment and implement the statutory responsibilities and policies of the regulatory agency.

One of the most common characteristics of regulated companies generally has been their resistance to accounting standards which were designed in the framework of regulatory principles. In numerous instances companies have had the aid of public accountants in this resistance, which at times has actually amounted to assaults on regulatory accounting. *In the Matter of the Montana Power Company* 4 FPC 213,252 et seq.

The conclusion is practically inescapable that area rate regulation applied to pipeline production, even if confined to Phase I only, would result in a downgrading of accounting standards applicable to such production. The circumvention of prescribed accounting controls would be rather easy unless the Commission were to see fit to require that affiliated producers and pipelines follow the same uniform accounting requirements.

Q. Aside from the downgrading or process of erosion which you have just discussed, do any other accounting problems or complexities occur to you which you feel the staff has not envisioned in connection with establishing area rates for attributing value to pipeline produced gas? A. Yes, there are several. Based on the testimony given in its

[4182]

case in chief the staff, in my opinion, has not given adequate attention to the accounting problems which the rate policy it advocates would generate and therefore has not evaluated all of the relevant pros and cons surrounding its advocacy. I would point out that accountants sponsored only a minor portion of the data relied upon by the staff and none of these witnesses attempted to come to grips with accounting problems inherent in the staff proposal, except to the extent Mr. Raymond did so in an income tax

[4182]

context. The policy witness, Mr. Deutsch, made assumptions and reached conclusions concerning accounting matters which in my judgment reflect inadequate consideration of what is involved. I have reference, for example, to his testimony at pages 622-625, 2192-2195, 2482-2483, 2506-2507, 2513, and 2433-2434 as well as some of the other testimony to which I make reference elsewhere in my testimony.

Q. In your judgment, is it practicable to include features in an accounting system which would accomplish a reasonable matching of costs and revenues with respect to each of several vintages of gas? A. It would not be difficult to devise suitable accounts for recording revenues or direct development and production costs associated with any given vintage of gas. However, the matching of appropriate exploratory and other indirect costs with the revenues from a particular vintage of gas presents relatively complex problems. Allocation of indirect costs which

[4183

are incurred at a time and in a context so that association with any given revenues is reasonably apparent frequently can be accomplished. This, however, is not attainable without controversy and wide differences of opinion. The development of rigid formulas of general applicability in this area may be a possibility, but they do not exist at present.

There is little hope of developing techniques under which exploratory costs such as dry hole losses, rentals, and lease charge-offs could be treated as relating to any given gas discovery or gas production. Certainly neither the present Uniform System of Accounts prescribed for pipelines nor the accounting principles employed by oil and gas producers generally would provide a suitable vehicle for accomplishing this objective. Moreover, a physical or other basis on which an association of those costs with particular gas could be rationalized is simply non-existent. Generally speaking, revenues of a given year provide the funds for exploratory

costs incurred in that year. This is the basis of the practical application of the cost and revenue matching principles used in practice and is also the basis of the Uniform System of Accounts prescribed for pipeline companies. When all of the pros and cons are considered it would be difficult to find a better or more rational rule for matching such costs and revenues, particularly for purposes of financial reporting. Any substantially different alternative would result in capitalizing or deferring

[4184]

exploratory losses. This would represent an inferior standard of accounting for a producer, particularly one whose revenues were not related to its own cost incurrence. Even if deferral of exploratory losses could be rationalized or gain general sanction, that circumstance would not of itself provide the basis of association of particular losses with particular gas production. Accordingly, the dilemna would still persist.

In view of the foregoing I can only conclude that adoption of an area rate valuation for pipeline and affiliated produced gas would result in a sacrifice of meaningful matching of costs and revenues.

Q. Assuming that area valuation of pipeline and affiliated produced gas would benefit consumers, as the staff contends, should it be rejected because of inability to achieve a proper matching of costs and revenues? A. There is difficulty with accepting an assumption of consumer benefits since I do not believe that consumers as a whole would receive any net benefits under the policy change proposed by the staff. I see a far greater probability that some producers would obtain unwarranted windfalls at the expense of consumers and that other producers would not receive the incentives needed to carry on exploration and development activities on the scale management would prefer. I believe, however, that maintenance of sound accounting procedures is absolutely essential to good business practice whether viewed from the stand-

[4185]

point of the regulatory body, management or the financial community. In my opinion, any regulatory device which would tend to undermine or inhibit the application of sound accounting principles would prove to be merely a gimmick. Accordingly, I believe that the accounting objections to area rate valuation of pipeline and affiliate produced gas are entitled to substantial weight in an evaluation of the proposed policy. The shortcomings of the staff's proposal are sufficiently numerous, however, that accounting considerations are not necessarily the one controlling factor which justifies rejection.

Q. On page 624 of the transcript, starting at line 24, Mr. Deutsch testified that his proposal "would greatly simplify the costing of production, leaving open only two items which currently, and in the future, will have to be separately considered for the entire transmission system regardless of what type of regulation is applied to production." He then suggests the probability of greater difficulty if those two items (rate of return and income taxes) were determined separately for the "nonproducing functions." Do you agree with this testimony of Mr. Deutsch? A. No.

Q. Why do you disagree? A. May I reiterate my belief that the claimed simplification of costing of production is without merit. My testimony has already developed why the costing procedures in each pipeline

[4186]

rate case in which company production was involved would be more difficult, more speculative and more controversial under the staff's proposals. Obviously, development of appropriate rules and procedures to cope with any attempts of the regulated companies to increase their profits through duplicate recovery of costs will be time consuming and require great skill. The staff's proposals will tend to cause occurrence of these regulatory problems rather than avoiding them. Once such problems arise, attempting to find

solutions and remedies will be tedious and costly.

The testimony of Mr. Deutsch to which you made reference appears to disregard the problems attributable to using a different method of valuing Phase I production for ratemaking purposes as distinguished from the rate treatment of any pipeline production other than Phase I. His testimoney starting at page 2443 of the transcript, line 24, as well as page 2506, line 20, shows that he proposes the establishment of separate accounts to record the costs and investments pertaining to "new" gas. It would seem to follow that separate accounts would be required for each subsequent vintage of "new" gas. There is no basis for concluding that use of area rates to value pipeline produced gas for ratemaking purposes would eliminate or reduce the accounting and reporting procedures required of pipeline companies. On the contrary the area rate proposal is certain to complicate and increase the burden of accounting and reporting.

[4187]

requirements, not to mention the increased need for surveillance of accounting by the Commission to insure that the costs recoverable from consumers under cost of service principles are properly identified and measured in the accounting and ratemaking processes. I am unable to understand how it would be possible to simplify the costing of gas production by adding accounting requirements which involve more accounts, more allocations and more areas of potential controversy, not to mention the added problems of surveillance and compliance.

It is difficult to believe that Mr. Deutsch has not substantially misperceived the nature of what would be required in a pipeline company rate case when he concludes that only the rate of return and income tax component "will have to be separately considered for the entire transmission system." Obviously every item of cost, of every nature, for each function of a pipeline company will have to be considered in any full fledged rate case and a decision reached

[4187]

as to whether the item should be included in cost of service to be borne by the ratepayers or whether it should be carved out because it would be applicable to the area rate valuation placed on company produced gas. A conclusion that this constitutes simplification of costing procedures does not appear to be rational.

Q. Does that complete your answer? A. I have one further brief comment. Mr. Deutsch's testimony which begins on line 1 of page 625 is a follows: "In fact, it

[4188]

would probably be more—rather than less—difficult to separately break out an income tax and rate of return for the nonproducing functions." Presumably Mr. Deutsch would not suggest that breaking out an income tax and rate of return for the nonproducing funtions is an appropriate procedure when a pipeline having production is regulated on a cost of service basis. If he is suggesting that it is a possible alternative approach in applying the staff's proposed area rate valuation to pipeline produced gas, this does not seem to reconcile with the proposition that both rate of return and income tax expenses can only be determined on an entity basis, not for some fragment of the entity. In my opinion it is impossible, therefore, to reconcile this particular testimony with that of Messrs. Shaffner and Raymond as well as other testimony of Mr. Deutsch.

Q. At page 622 of the transcript, beginning at line 12, Mr. Deutsch testified that "tax loss spillovers from the production function should in the future, as now, be utilized to reduce the tax liability of the transmission function." In your opinion, would this proposal actually benefit consumers? A. Under certain conditions a small benefit to consumers might be realized. I believe, however, that such situations would occur very infrequently. In general, if pipeline and affiliate produced gas is valued on an area basis in the future I would expect that the ability to salvage tax spillovers related to such gas for the benefit of consumers would be very limited,

[4189]

notwithstanding the contentions advanced by the staff.

Q. Would you please state the basis on which you reached your conclusion? A. Mr. Deutsch's statement relates primarily, if not entirely, to tax loss spillovers from the production function of a pipeline company rather than a producing affiliate. He testified that spillovers from affiliates would be shared by a pipeline parent, but the affiliate arrangement would not be advantageous in that regard (Transcript, page 2525). It is significant, however, that under Commission procedure the only way the tax loss spillover of an affiliate could affect the transmission tax allowance of a pipeline would be through the impact on the "effective" tax rate. Accordingly, the staff's contention would be fully meaningful only to the extent that a pipeline might carry on future production activities under an area rate in a producing division rather than through an affiliate. This would substantially limit the significance of the staff's contention that tax spillovers would be utilized to reduce transmission function expenses. In any event, I regard the staff's point as largely academic since the use of affiliates for future production under the proposed rate valuation would be more attractive and rewarding to the prospective producers than use of a pipeline division.

There seems to be inherent in Mr. Deutsch's statement of this matter a presumption that the transmission function of a

[4190]

pipeline company has a priority over any other activity of a pipeline company in the use of a tax loss spillover generated by a production department. To the extent this assumption is valid it does not follow that the situation envisioned by Mr. Deutsch would apply at all if the tax loss spillover from production activities were generated by an affiliate. The affiliated tax loss problem is being litigated in the courts. The possibilities for utilization of a tax loss

[4190]

of an affiliated producer to reduce costs other than those of the transmission function are so numerous that this "plus" factor claimed by the staff in support of its proposals has to be discounted very substantially. I suspect that in actual practice, instead of a nugget, the staff's proposed tax spillover will be more like Mother Hubbard's cupboard.

Q. Assuming that a tax spillover was generated by the production department of a pipeline company in connection with finding and developing gas reserves which were subject to area rate regulation, do you anticipate that there would be any difficulty in measuring the spillover to be used to reduce transmission cost of service at a given point of time? A. Yes.

Q. What difficulties to you anticipate? A. There is always the threshold question of whether such a spillover has to be shared between the transmission function and other activities. This problem, however, would not be peculiar to the area rate basis for assigning a value to pipeline produced gas. Accordingly, I do not propose to pursue it.

[4191]

The more relevant and ponderous problem is that of associating the special tax deductions arising from drilling operations with net revenues in order to compute a spillover, the benefit of which would actually flow to consumers. I am not raising a question whether a tax loss spillover during the development period before revenues from new gas are actually realized could be utilized to reduce transmission expenses. I am assuming, as I believe the staff has, that such a spillover could be so utilized, at least theoretically. I am very concerned, however, whether as a practical matter, the benefit could be flowed through to consumers in a proper amount. I would emphasize that computing or estimating a realistic amount of spillover to be used prospectively in a rate determination would be very difficult. Any quantification would have to take into account both the dollar level and results of drilling activity, prospectively. Manage-

ment should have a rather good idea of the prospective dollar level, but it would undoubtedly be visionary to expect that revelations with respect thereto in a rate case would place the Commission's insight on a par with that of management.

Q. Would the problem of quantifying future tax deductions from drilling be any different if pipeline production were regulated on a cost of service basis, rather than area rate valuation? A. Yes, definitely.

[4192]

Q. Why is that so? A. In order to obtain an allowance under cost of service regulation for prospective drilling operations the pipeline company would have to prove to the Commission that its claimed costs were bona fide and reasonable. There would be no such requirement of the producer under area rate regulation. The prospective tax deductions, and, therefore the prospective tax loss spillover, could be computed with little difficulty when the prospective drilling costs of the particular company were established.

Q. On the basis of certain staff studies of pipeline producers as a group, Mr. Deutsch concluded that their investment per Mcf appeared to be higher than that of independent producers and pipeline affiliates (Transcript, page 619, lines 22-23). He also testified that pipelines are "more prone than are producers to purchase proved reserves" (Transcript, page 618). In your opinion, do these conclusions justify either condemning the cost of service regulatory method or the use of area rate valuations of pipeline produced gas? A. No.

Q. Would you explain the basis of your disagreement with the staff? A. I believe that analysis of the underlying data on which Mr. Deutsch presumably relied underscores the importance and superiority of individual company cost regulation as a means of

[4193]

coming to grips with any existing evil rather than condemning that method. The cost arrays which underly the composite unit costs for depreciation, depletion and amortization and return on production investment do not indicate that the solution lies in switching the regulatory policy so that arbitrary valuation of pipeline produced gas on an area rate basis, effective at some "cut-off" date which would be established.

Q. Have you prepared an exhibit which shows data supporting your opinion? A. Yes.

Q. I show you an exhibit consisting of a single sheet marked as Exhibit No. 59 and bearing the title "Pipeline Production Cost Arrays for D.D.&A. and Return at 6.5%, Year 1962," and ask you whether this exhibit was prepared by you or under your supervision? A. It was.

Q. Please explain what is shown on Exhibit No. 59. A. This exhibit was prepared entirely from data shown on pages 2 and 3 of Item I by reference.

Column (1) lists the fifteen pipeline producers which were included in the studies introduced in this proceeding as Item I. Column (2) shows the percentage which each company's Continental U.S. production represents of the total pipeline volume of 655,569,263 Mcf for 1962 taken into account by the staff witnesses in Docket Nos. AR64-1 and 64-2 in preparing

[4194]

the exhibits which have been introduced in this case as Items B and I, respectively.

Column (3) shows the unit cost in cents per Mcf for each company listed on the sheets representing 1962 costs for Depreciation, Depletion and Amortization (D.D.&A.). The weighted average unit cost and composite unit cost of D.D. &A. are shown on lines 17 and 18, respectively, in Column (3).

The explanation of column (3) applies to column (4) except that the latter contains the unit costs in cents per Mcf for return on production investment computed at 6.5%.

Q. What is your understanding concerning the extent to which the data shown on the exhibit are related to the conclusions of the staff concerning the investment costs of pipeline producers as a group? A. Nothing is shown on this exhibit that was unknown or unavailable to the staff when it prepared its evidence. In fact, column (3) is an array by companies underlying the pipeline group unit D.D.&A. cost of 4 cents per Mcf referred to by Mr. Deutsch at page 620 of the transcript, line 15. Mr. Deutsch also made a reference to "pipelines' higher lease acquisition costs" at page 619 of the transcript, line 12. Column (4) of the exhibit is an array by companies of the return component computed at 6.5% and stated at the unit cost per Mcf of production.

Q. How many pipeline producers are included in the arrays shown

[4195]

on the exhibit? A. Fifteen.

Q. How many companies had D.D.&A. unit costs below the 4 cents per Mcf composite cost which also approximates the weighted average? A. Nine.

Q. What percentage of the total volume of 655,569,263 Mcf was produced by the nine companies? A. 60.54%.

Q. What is the range of the D.D.&A. unit cost for those nine companies? A. From 0.4581 to 3.2497 cents per Mcf.

Q. Are any producers in the Appalachian gas field included in the nine companies? A. No.

Q. What is the corresponding range for the six companies whose unit D.D.&A. costs were above the 4 cent average? A. From 4.5089 to 12.9279 cents per Mcf.

Q. How many producers in the Appalachian gas fields are included in the six companies whose D.D.&A. costs are above the 4 cents average? A. Three.

[4195]

Q. Based on your understanding of the table which is shown on page 2219 of the transcript, what would be the allowance per Mcf in the modified area rate for production D.D.&A.?

[4196]

A. 3.95 cents.

Q. In your opinion does the array of unit costs shown in Column (3) justify fixing an allowance of 3.95 cents per Mcf for D.D.&A. applicable to all gas produced by these fifteen companies and other pipeline producer companies from properties acquired after some given cut-off date? A. No. I believe the array data indicate that such arbitrary action would be highly improper.

Q. Why do you hold this opinion? A. With respect to a majority of the companies for which the data are shown there is no indication that any of such companies require an allowance as high as 3.95 cents per Mcf for D.D.&A. Unless their experience in the future is considerably different from that of the past, it would grant them excessive profits or windfalls at the expense of consumers with no accompanying consumer benefit. With respect to those four companies whose experienced D.D.&A. costs are approximately 1 cent or less per Mcf, the possibilities for unwarranted windfalls would be extremely grave from a consumer standpoint and particularly offensive to the regulatory standards of the Natural Gas Act.

The array data in column (3) indicate further that with respect to the two companies having the highest unit D.D.&A. costs, namely, 11.2305 and 12.9279 cents, respectively, some appropriate action would be required by the Commission in a

[4197]

rate case to investigate whether these costs impose an unfair burden on consumers and then take further appropriate action under the broad powers of the Commission under

the Natural Gas Act to protect consumers from specific instances of excessive cost incurrence, irrespective of when the excessive costs occur.

Q. Referring to column (4) of the exhibit, how many companies have unit costs for return below the approximately 6 cents per Mcf average for the group? A. Eleven.

Q. What percentage of the total volume of 655,569,263 Mcf was produced by the eleven companies? A. 77.257%.

Q. What is the range of the return unit cost for those eleven companies? A. From 0.616 to 4.9878 cents per Mcf.

Q. Are any producers in the Appalachian gas field included in the eleven companies? A. Yes, one, namely United Fuel Gas Company. It has the highest unit cost of the eleven companies.

Q. What is the corresponding range of the four companies whose unit cost for return was above the approximately 6 cents average? A. From 6.2813 to 40.647 cents per Mcf.

Q. How many producers in the Appalachian gas fields are included

[4198]

in the four companies whose unit cost for return was above the approximately 6 cents average? A. Two.

Q. Based on your understanding of the table which is shown on page 2219 of the transcript, what would be the production return allowance per Mcf, assuming a rate of 6.5 per cent? A. 3 cents per Mcf, including return on working capital.

Q. How do you account for the wide disparity between the unit allowance of 3 cents per Mcf indicated on page 2219 of the transcript and the approximately 6 cents per Mcf group average shown in column (4) of your exhibit? A. May I point out that approximately 57% of the gas volumes accounted for in the exhibit by 8 companies carry a unit allowance, as shown in column (4), of less than 3 cents per Mcf. One other company, accounting for 3.58% of the total volume, carries a return allowance of 3.1849 cents per

[4198]

Mcf. Two other companies which do not produce gas in the Appalachian fields, and account for 17.279% of the total volume of production, have unit costs per Mcf of 16.-9026 cents and 40.647 cents, respectively.

The 3 cent return allowance shown on page 2219 includes 2.82 cents per Mcf on production investment which is assumed to be 50% depleted and therefore is allowed a return on only 50% of original investment. This is clear from calculation item a) shown at the bottom of page 2219 of the transcript,

[4199]

since the D.D.&A. allowance of 3.95 cents per Mcf is multiplied by 11 although the life of the property, including a lag period, is assumed to be 22 years.

The unit cost of return data shown in column (4) of the exhibit are based on average depletion of approximately 28%, or a rate base for the group which is approximately 72% of original investment. As the properties are depleted the rate base declines and therefore the return allowance declines accordingly. This is not true with respect to the return allowance as computed on page 2219 of the transcript. It is a fixed unit cost.

To make a valid comparison between the 6 cent per Mcf average allowance indicated by column (4) of the exhibit and the 3 cent allowance shown on page 2219 of the transcript, the 6 cents would have to be divided by two. The comparable unit cost for return is therefore 3 cents, without going into the question of whether any of the production volumes for 1962 are not normal. It would appear, however, that when comparable figures are matched there is little difference between the pipeline group experience for 1962 for D.D.&A. per Mcf and return allowance at 6.5 per cent per Mcf, compared with the area rate computations shown on page 2219 of the transcript.

Q. In your opinion does the array of unit costs shown in column (4) justify fixing an allowance of 3 cents per Mcf

for return applicable to all gas produced by these fifteen companies and

[4200]

other pipeline producing companies from properties acquired after some given cut-off date? A. No. I believe that such arbitrary action would be highly improper. I do not intend this to be a position, however, concerning the fair rate of return for any pipeline company.

Q. Why do you hold this opinion? A. With respect to these companies it is not known what legitimate investment they will make if they acquire additional gas reserves. Whatever each such company requires to succeed financially it should have, but this should not include returns on improvident or excessive investments in gas reserves. Past history indicates a good chance that in a number of instances the return at 6.5% would be less than 3 cents per Mcf. If history repeats itself, as it well could, there would be no justification for granting the lower cost producers windfalls at the expense of consumers with no accompanying consumer benefit. Such windfalls would seem to be distinct possibilites in the case of the pipeline producer whose return requirement at 6.5% for 1962 was approximately 2 cents per Mcf and for five others whose requirement on the same basis was substantially under 2 cents per Mcf.

The array data in column (4) indicate further that with respect to the two companies having the highest unit costs for return, namely, 16.9026 cents and 40.647 cents, respectively, some appropriate action would be required by the

[4201]

Commission or the staff in a rate case to investigate whether these costs impose an unfair burden on consumers and then take further appropriate action under the board powers the Commission has under the Natural Gas Act to protect consumers from specific instances of excessive cost incurrence, irrespective of when the excessive costs occur.

[4201]

Q. What does the array of D.D.&A. cost for independent producers show with respect to the most extreme unit cost on the high side? A. According to page 302 of Item H, the highest unit D.D.&A. cost was 9.0149 cents per Mcf for 0.105% of the total gas produced by independent producers and pipeline affiliates from gas only and gas condensate leases. The next highest unit D.D.&A. cost was 6.3505 cents for 0.012% of such total production for these combined groups.

Q. What conclusions do you draw from comparing that array with the one shown in column (3) of Exhibit No. 59? A. Valid comparisons are difficult because of the substantial differences in the numbers of producers and volumes involved. The pipeline group consists of fifteen companies which had production in 1962 of 655,569,263 Mcf. In contrast the combined independent producer and pipeline affiliate group consists of 68 companies which produced 4,913,032,909 Mcf of gas from their gas only and gas condensate leases in 1962. As normally would be expected the dispersion above and below the

[4202]

average appears to be less erratic in the case of the larger group.

The most significant difference which stands out in comparing the two arrays is the fact that three out of the fifteen pipeline producers have unit D.D.&A. costs which are substantially in excess of the highest unit D.D.&A. cost reported for the other group. These three companies account for 13.448% of the total production reported for the pipeline group. If 1.241% is eliminated as attributable to geographical location (Appalachian gas field), the remaining 12.20% of total production applicable to two companies can be characterized as having erratic costs.

In my opinion, erratic costs of a small group of companies should not be allowed to be either a controlling or

impelling factor in determining whether a drastic change in regulatory policy is desirable or expedient.

Q. Does a comparison of unit cost arrays for return of the two groups in question lead to any substantially different conclusions than you reached with respect to D.D.&A.? A. No. The production return array for independent producers and pipeline affiliates computed at 12% is shown on page 4 of Item H. The two highest unit costs relate to only 0.071% of the total gas production for the group. As shown by Exhibit No. 59, the two highest unit costs of return for the pipeline producers relate to 17.279% of the total production for the

[4203]

group. The costs of these two companies are the only ones which are significantly higher than the average of the group and would have to be investigated for abnormalities in order to be interpreted intelligently.

Q. When you prepared Exhibit No. 21 from responses to the Municipal Gas Group data request, did you consider including in that exhibit certain composite data reflecting the responses to the staff's Pipeline Production Questionnaire? A. Yes. I wanted to include composite data prepared by the staff so that all tables in Exhibit No. 21 would have been complete through the year 1962. I concluded, however, upon investigation after corrections to the initial staff composite data became necessary, that it would not be feasible to attempt to do this in the time which was then at my disposal. Accordingly, Exhibit No. 21, subject to minor exceptions, includes only data obtained from responses to the Municipal Gas Group's data request, as I previously testified.

Q. Has some of the staff composite data to which you referred in your answer been included in exhibits which have been admitted in this case? A. Yes.

Q. Referring to Schedule 1 of Exhibit No. 21, would you identify by reference to other exhibits, data which sup-

[4203]

plement this schedule? A. Schedule No. 5, Sheet 1, of Exhibit No. 5 (in column (b) on

[4204]

Line 7) shows the total gross investment in producing leases for PPQ pipeline respondents at the end of 1962, in the amount of $939,369,505.

Page 3 of Exhibit No. 6 shows volumes of company owned gas reserves of pipeline respondents in column (d). The data reported therein include volumes of reserves at the end of each of the years 1958 to 1965, inclusive, which are not shown on Schedule 1 of Exhibit No. 21.

Q. What data, if any, included in other exhibits supplement the data concerning property acquisitions shown on Schedule 2 of Exhibit No. 21? A. Schedule 3 (or page 6) of Exhibit No. 5 shows data on lines 1 to 7, inclusive, for lease acquisitions by pipeline company respondents during each of the years 1955 to 1962, inclusive. Producing lease acquisition costs for PPQ pipeline respondents are shown on line 4 and the sum of the costs for both producing and non-producing lease acquisitions is shown on line 7.

Q. Did you find that the data shown on Schedule 4 of Exhibit No. 21, relating to exploration and development costs, is supplemented in any other exhibit? A. Yes. Schedule 4, sheet 1 (or page 7) of Exhibit No. 5 shows xploration and development costs of the PPQ pipeline respondents for each of the years 1955 to 1962, inclusive, on line 4.

Q. Have you determined whether the data shown on Schedule 5 of Exhibit No. 21 relating to transfers from nonproducing to

[4205]

producing property by pipeline producers are supplemented in any other exhibit? A. Yes.

Q. What is the situation? A. Schedule No. 7 (or page 12) of Exhibit No. 5 includes data relating to the cost of

such transfers for each of the years 1955 to 1962, inclusive. Such costs indicated as applicable to the PPQ pipeline respondents are shown on line 4 of Schedule 7 of Exhibit No. 5.

Q. Are the production volume data relating to pipelines and affiliates shown on Schedule 6 (as revised) of Exhibit No. 21 supplemented in other exhibits? A. Yes. The annual production volumes of producing pipelines are shown in column (c), page 23 of Exhibit No. 6 (lines 2 to 9, inclusive) for each of the years 1958 to 1965, inclusive. The annual production volumes of Group 3 pipeline affiliates are shown in column (c), page 25 of Exhibit No. 6 (lines 3 to 10, inclusive) for each of the years 1958 to 1965, inclusive.

Q. Schedule 7 (as revised) of Exhibit No. 21 relates to gross investment and gas reserves of Group 3 pipeline affiliates. Did you find data in other exhibits which supplement what is shown on Schedule 7 Revised? A. I did not find any amount in other exhibits for gross investment of pipeline affiliates subsequent to 1961 which relates only to Group 3 affiliates. Table 19 (page 25) of Exhibit

[4206]

No. 6 shows the year end gas reserves of Group 3 pipeline affiliates for each of the years 1958 to 1965, inclusive, in column (b), lines 3 to 10, inclusive.

Q. Schedule 8 of Exhibit No. 21 relates to property acquisitions of Group 3 pipeline affiliates. Did you find data in other exhibits which supplement what is shown on Schedule 8? A. No.

Q. Did you investigate whether the data shown on Schedules 9 and 10 relating to Group 3 pipeline affiliates are supplemented in other exhibits? A. Yes.

Q. What was the result? A. About the same as in the case of my investigation of whether data supplementing what is shown in Schedules 7 and 8 of Exhibit No. 21 are shown in other exhibits. Data pertaining to Group 3 re-

spondents are not shown separately in Exhibit No. 5. In preparing the various schedules of Exhibit No. 5 the staff witness treated Group 3 and Group 4 pipeline affiliates as one combined group rather than two separate groups.

Q. I show you an exhibit consisting of a single sheet marked as Exhibit No. 60 and bearing the title "Cross References to Data (years 1955-62) Supplementing Pipeline Company Data Included in Exhibit No. 21", and ask you whether this exhibit was prepared by you or under your supervision? A. It was.

[4207]

Q. What does this exhibit show? A. It is a summary which contains cross references between the pipeline company data included in Exhibit No. 21 and certain supplementary data, most of which have already been mentioned in my testimony. Column (1) lists the general categories of composite data presented in Exhibit No. 21 relative to producing pipeline companies. The schedule of Exhibit No. 21 which contains a particular type of data described in Column (1) is identified in Column (2). Appearing in Columns (3), (4), and (5) are cross references to Staff Exhibits and the Composite Summary identifying data shown therein for the years 1955-1962 which supplement the data appearing on the indicated schedules of Exhibit No. 21.

Q. I show you a document consisting of a single sheet marked as Exhibit No. 61 and bearing the title "Data (years 1955-62) Supplementing Pipeline Affiliate Data Included in Exhibit No. 21", and ask you whether this exhibit was prepared by you or under your supervision? A. It was.

Q. To the best of your knowledge does this exhibit present the subject data correctly? A. It does.

Q. What is it intended to show? A. It presents data for each of the years 1955 to 1962, relating to Group 3 Pipeline Affiliates which supplement the data

[4208]

presented in Schedules 7, 8, 9 and 10 of Exhibit No. 21, relating to such companies for the years 1940 to 1954, inclusive.

Q. What is the source of the data shown in Exhibit No. 61? A. All of the data shown, except owned gas reserves, were obtained from Volume 3 of the Staff Composite Summary of Responses to the Pipeline Production Questionnaire submitted by Group 3 Affiliates. The page references to Volume 3 are shown, for each column of data, on Line 9.

Q. Does Exhibit No. 61 identify the particular data shown in Exhibit No. 21 which it purports to supplement? A. Yes. This is covered by Line 10. Both Exhibit No. 21 and the Composite Summary of PPQ responses show breakdowns, however, that are not shown separately in this Exhibit.

Q. Do the data shown or referred to in Exhibit No. 61 together with the references to Staff Exhibits Nos. 5 and 6 and Composite Summary, which you have covered in your testimony and summarized in Exhibit No. 60, represent everything that is required to bring down or supplement the composite historical data presented in Exhibit No. 21, through the year 1962? A. Yes, with minor exceptions. The owned reserve data are actually shown through the year 1965, rather than 1962, in the references to Exhibit No. 6.

Q. Would you please clear up the minor exception you just mentioned?

[4209]

A. Schedule No. 1 of Exhibit No. 21 does not include the exploration and development gross investment of Group 1 pipeline companies for any year subsequent to 1954, as explained in footnote 2 of that schedule. The amounts reported for this item on page 41 of the Composite Summary (Volume 1) are as follows:

[4209]

1955	$35,577,774
1956	38,565,347
1957	41,891,288
1958	37,114,253
1959	39,319,609
1960	45,693,214
1961	40,265,425
1962	43,316,968

Schedule No. 7 (Revised) of Exhibit No. 21 does not show the gross Production Investment at December 31, 1962 for Group 3 Affiliated Producers. (Reference is made to Column (3) of such schedule.) According to page 485 (as revised) of the Staff Composite Summary (Volume 3) this amount of gross investment was $385,810,348.

Q. Does that conclude your testimony? A. Yes.

[4210]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

In the Matter of
Pipeline Production
Area Rate Proceeding

Docket No. RP66-24

PROPOSED REBUTTAL TESTIMONY OF MELWOOD W. VAN SCOYOC

Q. Are you the same Melwood W. Van Scoyoc who previously presented testimony in this proceeding on behalf of the Municipal Gas Group of Intervenors? A. Yes, I am.

Q. With respect to what particular issues or subject matters is your rebuttal presentation directed? A. In general my testimony is intended to rebut certain testimony of the witnesses: W. M. Elmer, M. J. Peck, E. L. Dunn and Norman Deutsch.

WILBUR K. MILLER #5 1/2/70

IN THE

UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA

No. 23740

ON PETITIONS TO REVIEW ORDERS OF THE FEDERAL POWER COMMISSION

JOINT APPENDIX

PIPELINE PRODUCTION AREA RATE CASE
CITY OF CHICAGO, ILLINOIS
CITY AND COUNTY OF DENVER, COLORADO
THE MEMPHIS LIGHT, GAS AND WATER DIVISION
MEMPHIS, TENNESSEE
AND THE AMERICAN PUBLIC GAS ASSOCIATION,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent.

VOLUME II

(Page 387 to Page 781)

Washington, D. C. · THIEL PRESS · 202 · 393-0625

TABLE OF CONTENTS

REBUTTAL TO THE TESTIMONY OF W. M. ELMER

Q. The testimony of Mr. Elmer at Tr. 708 sets forth the position of the Pipeline Production Group that the Commission should price that part of the production of a natural gas pipeline company or of its producing affiliate delivered to its transmission lines at the effective area rate or rates per Mcf, but not in excess of the contract price where applicable; and that the Commission apply the same standards, principles and criteria in regulating such production, including exceptions thereto warranted by particular circumstances, as are applied in the regulation of jurisdictional sales

[4211]

of gas by other producers. The position of the Pipeline Production Group is that this basis of regulation should "afford a parity of rate regulatory treatment for pipeline owned or controlled production with other production." Do you agree with this proposed approach to the rate making treatment of pipeline company or affiliated gas production concerning which Mr. Elmer has testified? A. No. In my opinion, it is without economic justification and would be unfair to consumers.

Q. Would the so-called "parity approach" which Mr. Elmer has urged the Commission to adopt require a drastic change in the regulatory policy of the Commission as sanctioned by the courts? A. Yes, it would.

Q. Would you now state briefly the reasons why, in your opinion, the proposal by the Pipeline Production Group is without economic justification and would be unfair to gas consumers? A. Economic justification for abandonment of the court approved "just and reasonable" cost of service standard for the pipeline and affiliate production, now firmly embedded in the regulation of natural gas pipeline companies, must be predicated upon a showing that the existing regulatory method is inimical to the interests of gas consumers and/or the investors in pipeline company securi-

[4211]

ties. Based on my studies of the matter, I am convinced that the existing regulatory standard results in a reasonable balancing of the interests of both the gas consumers and investors in pipeline company securities and that the adoption of the proposal of Mr. Elmer to utilize area rates for pricing gas produced by pipelines and their affiliates would unnecessarily burden consumers

[4212]

and provide unwarranted profits to the equity investors of some pipeline companies.

Assuming that the approach used in the Permian Basin Area rate case is ultimately adopted for the regulation of the rates of the so-called independent producers, such approach would not necessarily have any applicability to pipeline and affiliate produced gas. A pipeline company might receive an unwarranted windfall under area rates on the one hand, or be subject to a severe penalty under certain conditions if it could not recover its cost at the area price. This points up a further objectionable feature which is in conflict with economic reality. There can be no certainty in advance as to the impact of the so-called "parity" treatment. In effect, the position of the Pipeline Production Group is that they are willing to accept the unknown future area rates for their produced gas on the assumption that if the independent producers can live under a certain price for gas, presently undetermined, "so can we." However, evidence has been offered that there should be certain exemptions by areas or in cases of higher than average cost production. Such proposals, if adopted, would surely lead to a standard of individual cost of service or area rate valuation for pipeline company production, whichever is higher.

If the pipeline companies in the Group are exercising prudent business judgment in taking the position stated by Mr. Elmer, they must expect the "parity" treatment to yield them a greater amount of net revenue than they could receive based on their own cost of

[4213]

service including a fair return on their investment. The pipeline companies have not demonstrated, however, that they actually require or are entitled to any more than their cost of service, including a fair return. The fact that they see the possibility of profit in excess of a fair return in the "parity" basis is fair to consumers, it is necessary to understand, among other things, the position of the consumer with respect to the unsuccessful drilling and exploration costs which have been incurred by the pipeline companies and affiliates during the approximately thrity years under the Natural Gas Act. The Uniform System of Accounts prescribed for pipeline companies provides that unsuccessful drilling and exploratory costs are to be treated as current expense and not capitalized as investment. Thus, under the cost of service method of regulation utilized by the Commission, the unsuccessful drilling and exploration costs represent a burden on the consumer which the pipeline recovers currently through rates charged for gas sold. Accordingly, these expenditures are not financed by capital funds or through retained earnings supplied by investors. Nor are they associated with a given gas discovery at a given time.

Should the Commission decide to switch from cost of service regulation to the brand of pricing urged by Mr. Elmer, it would encounter a serious stumbling block in attempting to separate

[4214]

exploratory costs incurred between existing production operations and the operations which would be related to the after-acquired reserves associated with Phase I. I have little doubt that this very difficulty, as well as difficulties inherent in separating producing operations and related costs into two or more categories, will be among the reasons advanced by the Pipeline Production Group in promoting the application of area rates to existing production operations of

[4214]

pipelines and their affiliates in Phase II of this proceeding.

There is another aspect of the problem which relates to the question of fairness. The granting of inducements to the pipeline companies through a "parity" approach as an assumed stimulus to exploration and production activities would not assure the consumers of any benefits. There is nothing to compel a pipeline company, even if so stimulated, to step up exploration and production activities or to make available any of the discovered reserves to its transmission system.

Q. At Tr. 713 Mr. Elmer expresses the opinion that the individual company cost of service can not be made compatible with production activities of pipelines and their affiliates. Do you agree with Mr. Elmer's opinion? A. No, I do not.

Q. Please explain why you do not agree. A. To the extent Mr. Elmer has attempted to support his opinion, it appears at Tr. 713-715. Mr. Elmer first states that he does not believe that the application of an increased rate of return to

[4215]

an individual company rate base is the solution to the problem. Secondly, he seems to be saying that the costs of gas producers can not be estimated as accurately or as satisfactorily as they can for a utility type of industry. Accordingly, he would rule out the individual company rate base or rate of return approach for pipeline or affiliated production.

One reason why Mr. Elmer reaches an erroneous conclusion is that he starts with an erroneous premise. This is demonstrated by his testimony that "Had the Commission not already made the determination that the individual cost of service approach is not appropriate for independent producers, we would not be in this type of proceeding today."

Mr. Elmer has ignored the nearly three decades of experience that the Commission has had in determining cost of

service for pipeline and affiliate production. Since the Commission's pronouncement relating to independent producers in the *Phillips* case, 24 FPC 537 (1960), to which Mr. Elmer alluded, it has made several cost of service determinations in pipeline company rate cases where production facilities

in pipeline company rate cases where production facilities
were involved. In none of such cases did the Commission suggest the inappropriateness of the cost of service approach claimed by Mr. Elmer.

In my direct testimony I referred to the workability and feasibility of the cost of service approach for pipeline and affiliated company production and the comparative risks of the pipeline companies and independent producers and I will not repeat that testimony here. I would only add thereto the opinion that all

[4216]

of the claimed difficulties and distinctions have already been successfully and satisfactorily resolved by the Commission in its many determinations of "just and reasonable" rates for pipeline companies having production in a department or affiliate.

Q. Mr. Elmer states his opinion at Tr. 716 that "a well-managed production department or subsidiary is an asset to the financial standing of the pipeline company" according to the belief of a majority of funds, pension trusts, security analysts. and other investment groups. If Mr. Elmer's opinion is correct, doest this mean that the financial community appraises the risk of pipeline and subsidiary production more favorably than they do the risk applicable to the independent producers? A. I believe this would be the logical conclusion derived from such an opinion and also from Mr. Elmer's testimony on cross-examination at Tr. 3063 that a well managed production department results, in fact, "in a lower cost of equity capital."

Q. Testimony has also been offered by Mr. Elmer at Tr. 717 that the ownership of gas reserves by a pipeline com-

pany or producing affiliate gives the pipeline a more flexible gas supply and that control of production allows greater swings in periods of maximum and minimum demand. Do you agree? A. To answer your question specifically, I do not agree. I dealt with this contention in my direct testimony and in view of Mr. Elmer's testimony on cross-examination at Tr. 3080 I see no

[4217]

need to amplify my testimony in this regard.

Q. Mr. Elmer at Tr. 717 gave as one of his reasons in justification of modifying the regulatory policy the follow ing:

> "When unused capacity develops in portions of the gathering and transmission systems, the pipeline producer or affiliated producer can intensify its efforts to develop production from geographic areas which will relieve the unused capacity problem.***"

Do you regard this as a valid reason for changing the Commission's rate regulatory policy? A. No, it is no reason at all.

Q. Please explain your answer. A. The solution of such a problem is not regulatory but managerial in nature. One of the most basic of managerial responsibilities is that of making the fullest possible utilization of corporate assets. A failure or refusal to do so could only injure the stockholders because it would prevent the fullest possible rendition of additional units of service at incremental cost. This is a basic axiom in obtaining the maximum utilization of the capital invested in the enterprise. Based on my knowledge of utility managements over a long period of years, I do not believe that Mr. Elmer has accurately portrayed either the attitude of management generally, or the course of conduct which a competent management would necessarily pursue if it were confronted with a situation such as he describes.

Q. One of the problems concerning the individual cost

of service approach referred to by Mr. Elmer at Tr. 713, is the risk that

[4218]

the cost of production may exceed the area rate and some intervenor, or representative of the Commission's Staff, "may contend that some portion of the costs should be disallowed." Do you believe that any real risk of this character will be present in the future? A. No, I do not. While the right to question the prudence of an expenditure by a utility, as well as the duty to do so under appropriate circumstances, always will and should exist, such questioning is done in relatively few rate cases. Moreover, the extreme burden which must be assumed if any claim of imprudence as to the expenditures of a utility is to be successful minimizes any theoretical risk. Neither exploration and development expenditures nor production costs have ever been disallowed by the Commission in the past on the grounds of imprudence, to my knowledge. I do not believe the problem envisioned by Mr. Elmer will be of any significance in the future.

Q. Mr. Elmer testified at Tr. 712-713 that without a "parity" of rate treatment he did not see how any pipeline management can be expected to continue investing in production operations. What is your view in this respect? A. In my direct testimony I stated that whether or not a pipeline company should engage in production operations and the extent thereof was a decision for management. During the past three decades some pipeline companies have extensively engaged in production operations and some have not. Two or three pipeline companies have discontinued

[4219]

their production operations and sold their reserves and properties but retained the right to purchase the gas that had been discovered. Several existing and new pipeline companies have entered into the production activity since 1938.

[4219]

Several pipeline companies in business at the time the Natural Gas Act was passed have substantially expanded their production operations and others have not.

Undoubtedly, the incentives and motivations of managements as to production activities have differed. I would expect them to continue to differ in the future regardless of the rate making treatment used by the Federal Power Commission. However, it is significant that during this long period of regulation by the Commission on a cost of service basis there has been a very substantial increase in the amount of money invested by pipeline companies and their affiliates in gas production and in their expenditures for exploration and development expenses. I expect this trend to continue in the future under the cost of service approach. Other than the expectation of a windfall, I cannot conceive of a more favorable climate or incentive for gas exploratory activities of a pipeline company than the opportunity to recover through rates, (1) the cost of unsuccessful wells and other exploratory efforts, (2) a fair return on the net investment in leases and producing wells and (3) the recovery of production costs including depreciation, depletion and amortization.

Q. If what you state as to the advantages of the cost of service method is correct, how do you explain the assertion by the Pipeline Production Group witness that the "parity" treatment is

[4220]

essential for the good of the gas consumer and the industry, that they lack the incentive to engage in production activities without it? A. Based upon my long experience in the regulatory field I believe I understand the reasons for their position. I do not question the sincerity with which these claims are advanced. I do question the validity of such claims.

Alert utility managements are always seeking methods and opportunities of increasing the return to their stock-

holders and I do not dispute their right or duty in this regard. Many claims of many varieties have been put forward over the years by utility managements in an effort to gain a higher return on invested capital. Invariably these claims included strong emphasis that they were in the best interests of the consumer and that unless they were granted the utility would not be able to attract capital and furnish reliable and adequate service to the public at fair rates.

But regulatory history tells us that the utilities grew and prospered despite the rejection of many of their claims even as the pipeline companies expanded and prospered under the cost basis of regulation after extravagant claims to obtain more were denied in the *Hope* decision of the United States Supreme Court and other decisions.

In this proceeding, the Pipeline Group Companies are making another, but not essentially different, effort to secure for their

[4221]

stockholders the opportunity to obtain a higher return from company or affiliate owned production than they believe is possible under the cost of service method. While the certainty of such higher returns as to future production is not as great as it is for the existing production of certain pipeline companies under Phase II, these managements are evidently convinced that a greater monetary reward is possible under the area rate valuation of their production and the production of their affiliates than would be possible under the cost of service method of rate regulation.

REBUTTAL TO THE TESTIMONY OF DR. M. J. PECK

Q. At Tr. 684 Dr. Peck refers to a "relative decline" in production activities due to a lesser incentive and then attributes this alleged decline to the ratemaking method which has been employed for pipeline production activities. The "relative decline" to which he refers is explained at Tr. 685,

[4221]

686 and relates to the decline in the percentage of pipeline and affiliate produced gas to total gas marketed during the period 1955 to 1962. In your opinion, is there a relationship between the decline in the percentage of produced gas to total gas marketed and the Federal Power Commission's treatment of producing properties in determining "just and reasonable" rates for natural gas companies during the period from 1955 to 1962? A. No, sir. Altogether different reasons were responsible. From my research and study of this question, it is evident that there is no cause and effect relationship between the decline in the

[4222]

percentage of gas produced by these companies to total gas marketed in this period and the Commission's cost method of regulation for production properties. The decline did not come, in my opinion, as a result from FPC ratemaking policies.

Q. What then accounts for the decline in percentage of gas produced to total gas marketed during this period? A. A combination of circumstances provides the real explanation of the decline in percentages of gas produced by pipeline companies to total gas marketed. The decline simply reflects a continuation of the trend that commenced after World War II.

Q. Will you explain? A. Yes. Prior to 1942 there were no FPC decisions to indicate its policy for regulating natural gas rates. During World War II there was little or no expansion of the natural gas industry, except as strictly related to defense. As a result, during the war years the growing demand for natural gas could not be satisfied and was pent up. With the end of the war and the removal of restrictions, the race began to meet the great demand through expansion of existing facilities and the launching of new long line pipeline projects. Further impetus to the expansion of the natural gas industry was brought about by the large increases which occurred in the prices of oil and coal upon removal

of price controls. This factor added to the attractiveness of natural gas since its price at that time, like that of electricity, remained relatively stable. Needless to say, rapid satisfaction of the demand for gas became an important influence on the course of events. The acquisition and development of gas reserves by

[4223]

pipeline promoters or by existing pipeline systems through exploratory efforts on acquired leaseholds alone could not be accomplished quickly enough to meet the rapidly increasing demand during the post war period, but gas reserves which had been discovered by independent producers were available through long term gas purchase contracts. To promoters of new pipelines and existing natural gas companies, these reserves provided the means of connecting a supply of gas in the shortest possible time. Also, such method of acquisition entailed no large capital outlay, thereby enhancing the feasibility of financing the project. The latter factor is still very significant in pipeline expansion.

Q. Did the Federal Power Commission issue certificates for pipelines which depended upon reserves obtained through gas purchase contracts? A. Yes. The Commission accepted gas purchase contracts as satisfactory evidence of a gas supply to support a pipeline project and issued certificates of public convenience and necessity on such showings.

Q. Were there other factors responsible for the trend to gas purchase contracts as a source of gas supply? A. Yes. Bankers were willing to advance funds required for pipeline construction and to underwrite debt issues on the basis of gas purchase contracts. There was no longer any need, as had been the case prior to World War II, for pipelines to purchase proven gas reserves at a large capital outlay or to engage in a time taking search for a supply of gas through exploration activities.

[4224]

As a result of this combination of circumstances, it became the style or "convention" as it were, in the post war expansion, to acquire gas reserves through purchase contracts. This trend alone was primarily responsible for the decline in the ratio of pipeline produced gas to total gas marketed. To attribute the decline to the Federal Power Commission's rate regulatory method is incorrect. Dr. Peck has simply taken certain statistics and assigned an erroneous explanation to them.

Q. Did this post war expansion of the pipeline industry entail the investment of large amounts of additional capital? A. Yes. The capital which has been invested in the securities of natural gas companies subject to the jurisdiction of the Federal Power Commission during the period 1945-1962 amounts to approximately $7.5 billion, (not including retained earnings of $675 million). An additional $1.3 billion has been invested during the four years 1963-1966, inclusive. Several of these companies, although subject to the Natural Gas Act, are engaged in large scale distribution as well as pipeline operations.

Q. How many new pipeline systems have been constructed under FPC authorization since the end of World War II? A. So far as I can readily ascertain, approximately 50 corporations have constructed new pipeline systems since 1945 under FPC authorization. In addition, the "inch" lines were converted from oil lines to natural gas lines. By reason of mergers and exemptions under the 1954 Hinshaw amendment to the Act, not all of such companies presently report to the FPC.

Q. Were there also large expansions made in the capacity of the existing pipeline systems after 1945?

[4225]

A. Yes. All of the existing major systems expanded in considerable degree.

Q. Can you illustrate the magnitude of this expansion? A. Yes. Eleven of the large pipeline companies reported a total plant at December 31, 1945 of $729,753,576. At December 31, 1962 their total plant amounted to $6,040,-327,385, an increase of $5,310,573,809. A further increase of $1,271,280,000 occurred in the four years 1963-1966.

Q. Do some of the eleven existing pipeline companies to which you referred own gas production properties? A. Yes. Eight of the eleven companies owned or controlled natural gas reserves either directly or through a subsidiary or affiliate in 1945. The other three companies subsequently acquired natural gas reserves and conduct production operations through subsidiaries or directly.

Q. Did any of the new lines constructed after the War acquire production properties or engage in exploratory activities directly or through an affiliate or subsidiary? A. Yes. Of the new lines constructed during this period, Texas Eastern Transmission Corporation, Trunkline Gas Company and Pacific Northwest Pipeline Corporation acquired production properties.

Q. Did natural gas companies which had little or none of their revenues subject to rate regulation by the Federal Power Commission also experience a declining trend in the relationship of produced gas to their total gas supply?

[4226]

A. Yes. These companies over the years have depended more and more upon purchases from independent producers and the decline in the percent of produced gas to total gas supply of such companies has generally paralleled that of companies subject to FPC regulation. Obviously, Federal Power Commission rate regulation cannot be blamed for their experience.

Q. Is Arkansas-Louisiana Gas Company one of these companies? A. Yes, None of its rates were subject to FPC regulation, with the exception of certain minor field sales, until it acquired Consolidated Gas Utilities Corporation in 1960. The company had no reason prior to 1960 to be

[4226]

concerned with or relate its policies to, Federal Power Commission rate regulation. However, the percentage of its produced gas to total purchased and produced gas declined from 61% in 1942 to 18.7% in 1955 and to 16% in 1962. In 1966 it was 10.2%. The Arkansas Commission is compelled by law in fixing the company's rates subject to its jurisdiction to allow it the fair value or reasonable market value of produced gas.

Q. What are the other companies in this category? A. One is Lone Star Gas Company. None of its sales were subject to Federal Power Commission jurisdiction from 1942 until 1960 when it commenced sales to Natural Gas Pipeline Company of America. The percentage of gas produced by its affiliate, Lone Star Producing Company, to total purchased and produced gas declined from 32% in 1942 to 16.13% in 1955. The percentage increased to 22% in 1962 and to 24% in 1966. Another such company is Mountain Fuel Supply Company whose rates are entirely subject to the jurisdiction of the Utah and Wyoming Public Service Commissions. In

[4227]

1942 it secured 88% of its gas requirements from its own wells. By 1955 this percentage had declined to 45.6% as the company increased its purchases of gas from independent producers and pipeline suppliers. In 1962 the percentage of produced gas had decreased to 33.6% and in 1966 to 22.4%.

In 1942 Mountain Fuel Supply Company reported owned gas reserves of 295,049,000 Mcf and in 1962, 701,268,000 Mcf, an increase of 137%. In 1942 the company's exploration and development expenses amounted to $147,551 and in 1962 to $1,199,466, or eight times as much. This cost was $1,595,015 in 1966. The company increased its investment in production facilities from $6,443,876 in 1944 to $22,061,480 in 1962 and to $25,497,016 in 1966. The Utah Commission which has jurisdiction over about 95% of

Mountain Fuel's sales has consistently used the cost basis of regulation.

Q. Would Mountain Fuel Supply Company represent a situation where under the cost basis of regulation there has been a substantial decline in the ratio of produced gas to total gas supply and at the same time a substantial increase in the ownership of reserves, gas production, gas production plant and exploration and development costs? A. Yes, that is correct.

Q. Is there any other large natural gas company not subject to FPC rate regulation which has experienced a declining trend in the relationship of its produced gas to total gas supply? A. Yes. Oklahoma Natural Gas Company is such a company. It is a wholly intrastate utility, operating in the State of Oklahoma

[4228]

and has never been subject to the jurisdiction of the Federal Power Commission. In 1945 the company produced 10,056,802 Mcf of gas from its own reserves and purchased 75,926,701 Mcf from other producers. In 1962 its production amounted to 10,476,000 Mcf, a slight increase. On the other hand, it purchased 156,633,000 Mcf in 1962 from other producers, an increase of 106% above the 1945 level. In 1966 the company produced 10,327,000 Mcf and purchased 172,023,000 Mcf. The percentage of produced gas to total gas supply declined from 11.7% in 1945 to 5.7% in 1962.

Q. Did natural gas companies subject to the jurisdiction of the Federal Power Commission expand their ownership of natural gas reserves and gas production under the cost of service method of regulation used by the Commission? A. Yes. For the pipeline companies for which data are included in Exhibits 5, 6 and 21, the reserves and annual production are as follows:

	(Companies)	Reserves Mmcf-14.73	Annual Production Mncf-14.73
1942	18	13,712,289	350,644
1955	20	16,432,263	627,440
1962	23	23,021,344	754,630
1965	23	20,502,926	887,902

Q. Did natural gas companies increase their investment in production facilities throughout the period of Commission regulation of pipeline production on the cost of service basis?

[4229]

A. Yes. Natural gas pipeline companies have made large scale increases in their production plant. For the pipeline companies for which data are included in Exhibits 5 and 21 the total production plant investment is as follows for the years shown:

	(Companies)	Amount
1942	18	$116,019,000
1955	20	379,034,000
1962	23	982,686,000

The 23 companies shown for 1962 added production plant of $104,152,000 in the years 1963-1966, inclusive, according to FPC statistics. These figures do not include the production plant of 15 other companies reporting to the Commission aggregating $82,532,312 which is in addition to the amount shown for the 23 companies. These amounts do not include gathering facilities or plant held for future use.

Q. Did natural gas pipeline companies increase their expenditures for exploration and development during the time they have been subject to Commission regulation of pipeline production on a cost of service basis? A. Yes, the total expenditures for exploration and development increased

very substantially. Data in Exhibits 5 and 21 show the following:

Year	Companies	Amount
1942	18	$ 2,445,670
1955	20	15,373,381
1962	22	23,285,554

[4230]

Q. Does the amount of $23,285,554 for 1962 represent the maximum annual amount expended for exploration and development by the 22 companies? A. No. In 1960, $33,-624,334 was expended by those 22 companies.

Q. What brought about the large decline in exploration and development expenditures between 1960 and 1962? A. Two companies were primarily responsible for such decline. El Paso Natural Gas Company reported exploration and development expenditures of $11,432,345 in 1960 and $5,-868,222 in 1962. Tennessee Gas Transmission Company reported exploration and development of $7,203,084 in 1960 and $545,188 in 1962. The total reduction of these companies amounted to $12,222,019. As the total reduction for the two years was $10,338,780, it appears that other companies increased their exploration and development expenditures by a net amount of $1,883,239.

Q. Do you know the reason for the decline in exploration and development expenditures reported by El Paso and Tennessee? A. I do not know the explanation of the decline in El Paso's reported exploration and development expenditures. The decline in Tennessee's reported expenditures is associated with the transfer of its production properties in 1961 to its affiliate, Tenneco Corporation, in a corporate realignment. A footnote to the company's consolidated financial statements for 1961 disclosed that effective with such corporate realignment, "the policy was adopted of capitalizing all non-productive well drilling costs and amortizing the cost of undeveloped oil and gas leases."

[4230]

Accordingly Tennessee's reported exploration and development

[4231]

costs for 1960 and 1962, are not comparable, and do not necessarily indicate curtailment of such activities.

Q. Do the facts you have given concerning the investment by natural gas companies of huge amounts of capital in production plant while under FPC rate regulation, and the increases which they have experienced in expenditures for exploration and development indicate that the Commission's cost rate base method has failed to provide and adequate incentive to own and expand production operations as indicated by Dr. Peck? A. No. In my opinion, the facts indicate directly to the contrary.

Q. Dr. Peck testified at Tr. 693 that rates to consumers should not be directly affected by the choices that are made by company managements between company production and purchased gas. Do you agree with this conclusion? A. No. This testimony, in my opinion, demonstrates that Dr. Peck is unfamiliar with the nature of the Commission's cost of service ratemaking method as applied to pipeline companies, the techniques used and the applicable regulatory principles.

It is axiomatic that the choices of management, whether wise or unwise, will have an effect on consumer rates under any regulatory method which attempts to achieve some ressonable degree of equilibrium between a utility's revenues and costs, including return on investment, which are actually experienced and are reasonably applicable to the service rendered. If this were not an objective or standard of the regulatory process, the concept of "just and reasonable" rates would, in effect, be reduced to nonexistence.

[4232]

The opportunity to earn a fair return is a constitutional right of a regulated company and this fact may not be dis-

regarded in carrying out the regulatory process. This may result in justifiable differences in rates for services which may appear on the surface to be identical. Costs need not be identical, however, in order to be reasonable. The earnings test is so fully embedded in the regulatory techniques currently and traditionally employed in this country that any suggestion for its abandonment is tantamount to proposing the abolition of regulation altogether. Any regulatory theory which does not have at its core the principle of "just and reasonable," applied in accordance with known and tested standards, is not useful. This is true in relation to regulation of natural gas pipeline companies under the Natural Gas Act as well as utility regulation in general.

Q. At Tr. 694, Dr. Peck states that if the pipeline is a high cost producer, the company itself will bear the additional cost while the individual cost of service method tends to shift the cost differences forward to the consumer. Would not the same price allowance for a pipeline's gas supply, however obtained, be of advantage to the consumer? A. Not necessarily. The fair return received by the high cost pipeline producer should not be reduced because of such high cost production assuming no imprudence in that activity is demonstrated. On the other hand, the low cost pipeline producer should not be permitted to secure a return on his production which exceeds a fair return.

[4233]

I also do not believe that there is any lack of "parity" in having one price for the independent producer and allowing a pipeline taking gas, even from the same supply, to recover its cost although, when such costs are related to the volume of production the resulting unit cost is different than the price received by the independent producer.

In the case of gas purchased by a pipeline company from independent producers a cost is incurred for such supply which is allowed to be recovered through rates. Where the gas supply is secured from leases owned by the pipeline

[4233]

company or affiliate, costs are also incurred. Some of these costs are current costs while others are capital costs (applicable to future rather than current production). When the costs determined under appropriate accounting procedures are related to a given volume of production, the unit production cost may be more or less than the unit price paid independent producers by the pipeline company for gas of equivalent usefulness. This is parity of treatment since the outlay and the recovery costs actually incurred by the pipeline company occurs in both situation. The existence of situation where the unit cost of purchased gas is different than the unit cost of produced gas does not invalidate the use of actual production costs, whatever they may be, as the basis for pipeline company ratemaking.

The pipeline company is not disadvantaged or discriminated against because the independent producer is receiving higher or lower returns on his investment than is the pipeline company.

[4234]

The financial risks of the pipeline company and the independent producer may be entirely different, and I think they generally are. The fact that independent producers receive prices for their gas which may differ from the unit production cost of the pipeline or pipeline affiliate does not provide any justification, in my opinion, for the substitution of a fictitious allowance for pipeline produced gas for the actual costs the pipeline incurs in producing gas, including a fair return.

We presently have situations where two or more pipeline companies are serving the same gas distributor at different rates. I have heard no one claim that this is unfair to the pipeline company who has the lowest delivery cost and that it should be permitted parity rate for serving the same market. Nor do I know of any claim that the pipeline company with the highest unit delivery cost is inefficient and should suffer the penalty of receiving less than a fair return by

having its rate reduced to that of the company having the lowest delivery cost.

Q. Dr. Peck testified at Tr. 696 concerning the need for the "spur of losses for poor choices and the carrot of above median rewards for good management" to increase efficiency, and cited an example where the consumer might have to pay the higher cost where the pipeline undertakes production activities as a matter of preference rather than to minimize costs. He also testified that the cost of service regulation is inconsistent with encouraging efficient exploration. In your opinion, is cost of service regulation inconsistent or incompatible with

[4235]

efficient operation of pipeline companies? A. No, in my opinion, it is not. Dr. Peck has failed to recognize that there is actually no irresolvable conflict between profit incentive and the individual cost of service method of regulation. He has overlooked the fact that any utility which operates under rates based upon its cost of service for a given test period has the same incentive as any other business concern to reduce its cost and such reduction of cost will increase its profits for the operating period affected. Under the Natural Gas Act such cost reductions are not automatically passed on to consumers and they cannot be recaptured for the benefit of consumers by regulatory action. They can only benefit the stockholders. In addition to being free from recapture of its earnings, a natural gas company may continue to charge and retain the revenues from excessive rates until they have been found by the Commission, after a hearing, to be unlawful or not to be the lowest reasonable rates. This provides management with ample opportunity and incentive to effect savings, and at the same time to be shielded from penalization for doing so. I do not mean to imply that if such cost reductions result in substantial excess earnings that they may not be reflected in lower rates sometime in the future because of Commission action.

[4235]

It is somewhat axiomatic under the Natural Gas Act that regulatory lags operate in favor of the natural gas company rather than the consumer when excessive rates are being charged. The Act further favors the company since it provides full opportunity for a natural gas company to put into effect rate

[4236]

increases at the first moment they are actually needed. Thus, there is little likelihood that a natural gas company would ever have to undergo an extended period of deficient earnings due to lags attributable to the regulatory process.

Q. At Tr. 697, Dr. Peck refers to the unpredictability of exploration costs and states that this unpredictability can be a major problem in cost of service ratemaking rather than a normal imperfection. Do you agree? A. No. This particular testimony again demonstrates Dr. Peck's lack or knowledge of the cost of service method of regulation as applied by the Federal Power Commission. The total exploration costs in any year can be and are predictable within rather close limits since they are subject to budget procedures. What cannot be predicted within such close limits is the share of the total annual exploration costs that is chargeable to operating expenses and the share that is capitalized.

Dr. Peck is apparently under the impression that for experience concerning a particular cost item to be valid for ratemaking purposes it cannot vary or fluctuate from year to year. He assumes, in effect, that the actual experience of a given test period will not be adjusted in the ratemaking process to allow for variations from such experience. A clearcut example of his misconception in this respect is shown by his testimony at Tr. 698, as follows:

> "*** in 1964 a dozen pipelines had no exploration activities. These pipelines, if 1964 were their base year for ratemaking, would have no allowance for unsuccessful exploration or dryhole expense

[4237]

> and would not receive any such allowance until after the costs were incurred."

Only moderate sophistication in the art of ratemaking is required to provide the knowledge that the experience of a given year for a cost item which may well vary from year to year, as a normal situation, will not be accepted in preference to the average cost of the item for a longer more representative period. Exploration and development costs allowed in pipeline company rate cases have represented the experience of the company averaged for several years. Furthermore, since ratemaking is prospective, *bona fide*, properly supported future exploratory programs would not be ignored in determining the costs in fixing future rates. The burden of justifying a rate increase is in all cases, upon the company.

Contrary to Dr. Peck's testimony (Tr. 698) there is no implied assumption whatever in the individual cost of service method that the exploratory activity would be at a "constant level, regardless of the needs or opportunities." In making allowances for exploratory costs, undertaken prudently to provide gas supplies for consumers at the lowest reasonable cost, the Commission has examined thoroughly the experience of pipeline companies as well as their authentic programs and has made an allowance in fixing the revenue requirement which would compensate the company for all of its reasonable exploratory costs.

[4238]

REBUTTAL TO THE TESTIMONY OF EDWARD L. DUNN

Q. Reference is made to the testimony of Mr. Dunn, particularly to the portion commencing with the answer on Tr. 766 commencing at line 15. In his answer, Mr. Dunn states;

[4238]

> "Where lack of regulation exists in the transactions with an affiliated seller, the price should be no higher than would be fairly payable in a regulated business by a buyer unrelated to the seller and dealing at arm's-length. This furnishes the same restraint as that from regulation."

Do you agree with this statement? A. If Mr. Dunn is suggesting that when affiliates are buyers and sellers the price should be no higher than the existing price as between unrelated buyers and sellers, then I disagree. The standard which has been established by most regulatory agencies and particularly the Federal Power Commission, is cost to the affiliate, including a fair return on the facilities devoted to supplying the goods and services. In a long line of decisions commencing with *Louisville Hydro-Electric Company*, 1 FPC 130, the Commission has declined to accept the claim that because the prices charged by the affiliate were no higher, or even less than those obtainable elsewhere in an arm's length transaction, they should be accepted as reasonable. The Commission instead has insisted upon adherence to the cost to the affiliate as the test.

Q. At Tr. 767 Mr. Dunn states:

> "Since June 7, 1954, there has been no regulatory significance due to affiliation in the regulatory review of the reasonableness of rates and charges for

[4239]

> gas sold by a producing company to an affiliated interstate pipeline company because the producing company has been subject to rate regulation. This is necessarily true, because regulation guarantees the integrity, fairness and reasonableness of such transactions among affiliates far more strictly than any other method of regulatory supervision or scrutiny."

Do you agree with Mr. Dunn that there is no regulatory significance due to affiliation in the situation he describes? A. No, I do not. The rate filed by a producer affiliate of

a pipeline company since June 7, 1964 and accepted by the Commission, while unquestionably lawful, may not be reasonable. This is demonstrated by the fact that in the rate case of *Union Producing Company*, Docket No. G-13811, et al., the Commission found that the increased rates which Union had collected from its affiliate, United Gas Pipe Line Company, under FPC filed rate schedules were not justified and such rates were ordered disallowed and denied. *Union Producing Company*, 31 FPC 41.

Moreover, on rehearing the Commission stated:

> "It is well settled that particular elements of a pipeline's cost may be determined in a proceeding separate from the overall rate proceeding."

The Commission distinguished between Union's sales to non-affiliated purchasers and its sales to United, stating:

> "As to its sales to United we have consistently held that where an affiliated producer is selling to a pipeline the certificated rate for such sales cannot be binding on the Commission in determining gas purchase costs in the pipeline's rate proceedings." *Union Producing Company*, 31 FPC 503, 504.

[4240]

Subsequently, in the rate case of *United Gas Pipe Line Company*, 31 FPC 1180, 1187, the Commission, after referring to the decisions of the D. C. Court of Appeals in *Mississippi River Fuel Corporation v. FPC*, 252 F.2d 618 and *Willmut Gas and Oil Company v. FPC*, 299 F.2d 111, said:

> "In view of these decisions it is entirely clear that we would be remiss in accepting Union's filed rates for United's purchase gas costs. The courts, in effect, place the filed rates of an affiliate in a different category than those of a non-affiliate. This follows reasonably because, as the court said, we are dealing with a single corporate structure. We must therefore do something more than accept the filed

[4240]

> rates, as United would have us, but we are not required to include a full-blown inquiry into Union's rates in the present proceeding."

Mr. Dunn's testimony that there has been no regulatory significance to affiliation since June 7, 1954 is completely in error.

Q. Mr. Dunn concludes his testimony at Tr. 767 by stating;

> "It is my conclusion that it is not only proper, but absolutely essential, that the Commission, in reviewing and determining just and reasonable rates for all 'independent producers' including that class of 'independent producers' which I have discussed, of dependent producers' which I have discussed, of methods and principles followed to determine justness and reasonableness for all 'independent producers,' including that class of 'independent producers' which I have discussed, whether it may be some 'cost' method, an area rate method, or any method which the Commission at any time in the future may select, and this is so whether it apply to gas described as 'old' gas or 'new' gas or by any other name."

Do you agree with this statement? A. I do not agree that Union is typical of independent producers or that it is necessary that the same regulatory methods be used in

[4241]

regulating Union's rates for sales of gas to its affiliate, United Gas Pipe Line Company, as may be applied in regulating the rates of independent producers. Union's affiliation with the purchaser (United) of approximately 80% of its production, the ownership of all of Union's common stock by United Gas Corporation (also the parent of United Gas Pipe Line Company) and the effects of these affiliated relationships upon the risks, and financial position and operations of Union are of signal importance in a determination of the reasonableness of the rates of United Gas Pipe

Line Company subject to the jurisdiction of the Federal Power Commission.

[4242]

REBUTTAL TO THE TESTIMONY
OF NORMAN DEUTSCH

Q. During cross-examination, starting on Tr. 2173, line 9, through Tr. 2174, line 7, Dr. Deutsch testified in substance that pipeline producers receive an unnecessary incentive under individual cost of service regulation because they get all of their costs no matter what the costs are, plus a return on investment. Do you agree with the contention that individual cost of service regulation of production provides unnecessary incentives? A. No.

Q. Would you explain why you disagree? A. First of all, such testimony implies that imprudent expenditures would be allowable by the Commission. While disallowances based on imprudence have been rare they have occurred and the Commission authority in such respect has been sustained Moreover a just and reasonable rate, determined on the basis of a given test year, with adjustments as appropriate, does not of itself assure that a regulated company will necessarily recover all of the costs it may incur, plus a fair return. If it incurs costs not contemplated in the test year data and there is no compensating factor attributable to increased output, the company is likely to earn less than the fair rate of return. The converse could also occur where revenues increase or costs are reduced from the test year level. If cost and revenue matching principles were improperly applied in determining the rate and this mismatching should bring about an incorrect result, this is no reason whatever for condeming

[4243]

that method of regulation as applied on an individual company basis.

[4243]

Mr. Deutsch has mistakenly equated the production cost incurred by any pipeline in excess of the national average cost he selected, with inefficiency (Tr. 2447). There has been no suggestion in his testimony that inefficiency exists among pipeline producers as determined under any criterion other than by comparison with the selected national average cost standard although he recognized that many other factors could contribute to the high cost of producing gas in in a given area. The average cost test has no prima facie validity whatever. Other tests would have to be applied before there could be a rational conclusion that a pipeline producer was inefficient in producing natural gas.

Q. If Mr. Deutsch's position as to the treatment of other production costs on an average basis were logical, would it not compel the use of an average rate of return for all pipeline companies rather than a rate of return on an individual company basis? A. Yes, I believe this would logically follow from such proposal.

Q. What is your opinion as to the Staff position which in effect proposes to allow producers who have the geographic advantage or good fortune to be able to produce for less than the selected national average cost to retain the full amount of their excessive returns? A. The result of the Staff proposal which is to allow the fortunately situated producer to obtain an unnecessary special incentive, is that consumers would pay more for their gas in order to provide

[4244]

such incentives. There is no sound regulatory underpinning, particularly in the Natural Gas Act, for such proposed policy. In the actual world of reality the proposed policy would discourage or eliminate the high cost producer, not on the basis of an objective determination that the high costs were actually unjustified, but as the result of adopting a policy which would have such effect and, which would, at the same time, grant windfalls to some producers at the expense of consumers. If the existing policy is failing to

achieve sound regulatory goals, there must be some better solution than substituting a policy having such unreasonable results.

Q. Assuming that there is a problem of high cost inefficient pipeline production, as Mr. Deutsch suggests at Tr. 2481-2483, do you believe that the use of area rates to value pipeline produced gas for ratemaking purposes would provide a practical and effective approach for solution of that problem? A. No. However, I am far from being satisfied that the Staff's limited basis of interpreting or defining inefficient production establishes that such a problem actually exists. It may or may not exist. The spectrum of the cost array is quite substantial. However, based on the considerable amount of production cost data I have reviewed over the past 20 years in a large number of rate proceedings, I am firmly of the opinion that inefficiency as such is of minor consequence. In any event, I certainly would not accept as valid the proposition that because a given cost is higher than some average it constitutes prima facie

[4245]

evidence of inefficiency or any other deficiency that would justify the drastic intervention and changes proposed as the remedy.

There is absolutely no basis for granting a low cost pipeline or affiliated producer a windfall. If the higher than average cost production, which apparently forms the basis for the Staff position (Tr. 2482), is due to inefficiency or imprudent expenditures, the Commission has adequate investigative powers to determine the reason and the power to apply appropriate remedies within the framework of the Natural Gas Act.

Q. Does not the proposed area rate ceiling based on a national average protect consumers from having the burden of paying for high cost production? A. Some consumers might benefit in this respect, but it could be at the expense of other consumers who were required to pay more for gas

[4245]

than its legitimate cost. I regard the assurances attributable to the ceiling feature of the area rate proposals in this proceeding as being of limited protective value. It may tend to discourage the production, acquisition or transfer of relatively high cost gas as well as exploratory activities at any given point of time. For example, Mr. Corrin made it very clear that unless the area price was sufficiently high, Consolidated would not continue with its exploration program in South Louisiana (Tr. 3713, 3714).

Mr. Deutsch, however, has clearly indicated that there

[4246]

can be exemptions from the ceilings (Tr. 2363 and 2386). The dilution of claimed benefits through this feature could very well occur. It is naturally to be expected that high cost pipeline producers and affiliates will take every possible legal step available to them to obtain a return of their legitimate costs, including a reasonable profit, in their rates. If they are successful on any substantial scale the consumers will simply be victimized with paying rates which represent area rate or cost, whichever is higher. I would suggest that the Commission is not so limited in its authority under the Natural Gas Act that it needs to regulate under a policy which exposes gas consumers to this serious risk.

Q. In your opinion, did Mr. Deutsch properly appraise the administrative burden of weeding out inefficient production under cost of service regulation in his testimony at Tr. 2481-2484? A. No. I do not believe that his conclusions were well founded.

Q. What is the basis of your opinion? A. Apparently Mr. Deutsch is of the opinion that in the absence of his area rate proposal each producing pipeline would have to be checked periodically, or at least in each rate case, as to whether its practices resulted in excessive costs and whether its "production patterns" and "gas patterns" (to use his phrases) were normal. Since the test proposed to be applied is that of an area rate based on a national average cost, a

conclusion on that basis could be reached very quickly and with little effort for pipeline producers whose costs were in line with, or lower than, such area rate.

[4247]

As to the remaining so-called inefficient high cost producers, Mr. Deutsch testified (Tr. 2483) that "It would be an extremely more complicated process and it would involve a great deal of work. It is a very complex problem." But the simple solution proposed by the Staff to this very complex problem is somewhat analogous to that of the quick and easy solution of the Queen in Alice in Wonderland of "off with his head."

There also appears to be a presumption underlying Mr. Deutsch's purported analysis that any pipeline producer could always obtain the equivalent volume of produced gas from an independent producer at a price not to exceed the area ceiling. Obviously this possibility would have to be ruled out in a number of instances.

The only conclusion that could properly be drawn from this particular testimony is that the Staff of this Commission, charged with the duty of protecting the interests of gas consumers an of ascertaining facts and advising the Commission as to "just and reasonable rates" has, over a long period of years, ignored or disregarded this alleged prima facie evidence of inefficiency in gas production by certain pipeline companies. This can only suggest massive incompetence, or even dereliction, on the part of the Staff. I do not believe that Mr. Deutsch really understood the true implication of his testimony in this respect.

[4248]

Q. Is it not true, Mr. Van Scoyoc, that until an area rate was determined there was not available for application to pipeline or affiliate production a means for testing inefficiency? A. No,that is not correct. Such a premise would be wholly false. The Staff has been well aware over the

[4248]

years of differences in the cost of production of individual pipeline companies. It has known, for example, that the cost of producing gas in the Appalachian area was several times the cost of producing gas from the Panhandle field. The Staff has also been aware of the prices which pipeline companies have paid independent producers and that in many cases the prices paid were in excess of the pipeline company's production cost and in some instances they were less. If someone on the Staff had really believed that inefficiency was demonstrated by these cost and price differentials, the figures were available for presentation in pipeline rate cases and for advising the Commission of such conclusion.

Long ago, the courts held that a "just and reasonable" standard was not satisfied by the use of comparative rates charged by other utilities. To charge inefficiency in gas production on the basis of mere cost or price comparisons is to charge inefficiency in any phase of pipeline company and public utility operations where differentials exist in the costs incurred or in the rates charged customers. This approach has been discredited many times.

[4249]

In my opinion, it taxes the limit of prudence for the Staff to proceed in this case on the theory that a claimed normal or standard cost which equates with a national average cost determined in area rate cases is so conceptually sound that it should supersede long standing existing court approved procedures. Until there are more facts and experience with which to evaluate the workability of area rates as applied to independent producers (assuming court approval), it makes no sense whatsoever to propose it as a substitute immediately for a system that has been successfully applied to pipeline and affiliated producers for nearly 30 years.

Q. Mr. Deutsch testified at Tr. 2475, line 1, that his proposed change in rate policy would result in a lower cost of gas to consumers. Do you agree that Mr. Deutsch was justified in reaching that conclusion? A. No.

Q. Why do you disagree? A. My disagreement is because I do not believe that Mr. Deutsch's conclusion is justified on the basis of his own testimony.

Q. Would you please explain this? A. Mr. Deutsch testified on direct that his proposal would "penalize inefficient operation" (Tr. 584, line 17). During cross-examination he testified that the basic premise of his testimony was that consumers would be protected by removing inefficient high cost production (Tr. 2481). He agreed that there would be no reasons for the policy change he had proposed except that

[4250]

"inefficient high cost production" in fact exists (Tr. 2482, lines 2 through 8). The only reason given by Mr. Deutsch, however, for concluding that production was "inefficient" was that the cost was in excess of the "average cost standard" and "standard cost" (Tr. 2447, lines 19-25: Tr. 2483, line 4; Tr. 2504 line 5; Tr. 2475, Lines 17-13; cf. Tr. 2480, lines 17-18). In fact, Mr. Deutsch agreed that the Commission's regulation of pipeline companies under cost of service principles required that any cost be reasonably and prudently incurred (Tr. 2487, line 7).

Although Mr. Deutsch's testimony at Tr. 2496, implies that each pipeline producer would get less for its own produced gas under area rate valuation than under cost of service, it is evident that this simply is not so. If there is production which costs more than the average cost there has to be a compensating amount of production which costs something less than the average cost. Consequently the computed average cost standard, unless it has more substantive support than that of mere mathematical derivation, is little more than a gimmick. As proposed, it is not anybody's cost, and is not necessarily representative of any pipeline producer or any group of pipeline producers. In this connection, I certainly cannot agree with Mr. Deutsch's characterization of this type of mathematical average when he refers to it as being "normal" or "standard."

[4251]

However, Mr. Deutsch does not propose to "stand pat" on his average cost standard concept under all conditions. Although he testified that all producers who have above average costs "will have to come down to the average" (Tr. 2458, line 19), he also testified that special exemptions from the area rate could be allowed (Tr. 2365, 2486, 2488, 2274). The willingness on the part of the witness to modify this standard casts grave doubts on the regulatory policy which is actually being proposed. This proposal could well mean that pipeline produced gas would be valued for ratemaking purposes at an area rate or cost of service, whichever is higher. In my opinion this double barreled assurance in favor of the pipeline producers at the expense of consumers proposed by Mr. Deutsch collides head-on with the "consumer-oriented objectives" of the Natural Gas Act. Moreover, it seems quite clear that while gas consumers in some areas might benefit, gas consumers in other areas could suffer a detriment.

Neither Mr. Deutsch nor any other Staff witness testified that regulation of pipeline production on a cost of service basis is impracticable, unreasonable or administratively unfeasible. The record of its administration by the Commission demonstrates the contrary. No question of expediency, therefore, is involved in the issues here presented.

Q. Does that complete your testimony? A. Yes.

* * *

[4253]

Rebuttal Testimony of Maurice F. Wilhelm, Jr.

* * *

A. My name is Maurice F. Wilhelm, Jr. and I live in Birmingham, Alabama. I am a staff assistant to the Vice President and Treasurer of Southern Natural Gas Company and I am head of the Systems and Procedures Department.

Q. Please outline briefly your educational and professional experience.

* * *

[4257]

Q. Have you made the same determination for natural gas pipelines? A. Yes. The incremental increases in net plant for the major Class A & B pipeline companies from December 1962 to December 1966 would, on a basis comparable to that used for independent producers, require financing on a composite basis with 55% debt and preferred stock and 45% equity funds to produce the change in composite ratio over that period.

Q. Were you able to support the capitalization ratios for independent producers used by Dr. Shaffner in his testimony? A. Workpapers setting forth the calculation of the composite capitalization ratios used in his testimony were not provided by Dr. Shaffner, We therefore made a determination of what the capitalization structures of these companies was. The ratios for 1962 are set forth in Schedule 8 and the capital structure of each company for 1962 is shown on Schedule 10. The composite ratios of 14.94% long-term debt, .48% preferred stock, and 84.58% common equity shown at the bottom of Schedule 10 indicate that Dr. Shaffner's calculation of composite ratios was almost the same as ours.

Q. You have said that you have eliminated from Dr. Shaffner's

[4258]

1962 calculations those pipeline companies not classified as producers by the staff. What effect does this have on Dr. Shaffner's rate of return calculation? A. The difference is not extreme, but, when combined with other points, it will support our argument that the typical producing pipeline is not significantly different from the typical independent producer and thus will not enjoy an unreasonable return

[4258]

on equity if area rates are established for pipeline production. The composite capitalization ratios for this group of producing pipelines are shown on Schedule 4 as of December 31, 1966 and on Schedule 9 for December 31, 1962. These composite ratios are 56.97% long-term debt, 8.42% preferred stock and 34.61% common equity at December 31, 1966. The comparable ratios at December 31, 1962 are 58.39%, 8.32% and 33.29%, respectively. The 1966 ratios are significantly different from the 1966 capitalization ratios of the major pipelines who are not producers shown in Schedule 12. The composite ratios of these nonproducers were 63.27% long-term debt, 5.07% preferred stock, and 31.65% common equity.

Q. Are all the pipeline companies listed in the staff's Group 1 producers of natural gas? A. No. Actually eight of these companies, Alabama-Tennessee Natural Gas Company, Cities Service Gas Company, Kentucky

[4259]

Gas Tr ansmission Company, Lone Star Gas Company, Mississippi River Transmission Corporation, Texas Gas Transmission Corporation, Trunkline Gas Company, and United Gas Pipeline Company had no production in 1966 or de minimia production. These companies probably should have been included in Schedule 12, and excluded from the other schedules as nonproducers. However, their inclusion facilitates comparison with the staff's data.

Q. Why do you believe that Dr. Shaffner's comparison of pipeline producers and independent producers is not appropriate? A. As indicated in the preceding answer, a comparison should not use all companies comprising the natural gas pipeline industry but rather only those who are classified as producing pipelines. Second, in comparing the two groups, it is not appropriate to use a comparison of composite capitalization ratios to draw conclusions regarding financing costs of typical companies within each group. To illustrate: If we look at the composite ratios of the producing pipelines at December 31, 1966 on Schedule 4, we

see that long-term debt is 56.97%, preferred stock is 8.42% and common equity is 34.61%. However, these composite ratios do not represent a typical pipeline producer. It can be seen on Schedule 2 that only six companies out of the group of 27 companies listed have a lower common equity ratio than the composite common equity

[4260]

ratio of 34.61%. The typical producing pipeline company has capitalization ratios approximating the averages shown at the bottom of Schedule 2, i.e., 47.31% long-term debt, 3.34% preferred stock, and 49.35% common equity. Had the eight nonproducing pipelines previously mentioned been excluded from Schedule 2, the typical pipeline producer capitalization ratio in 1966 would had been 45.68% debt, 3.97% preferred stock and 50.35% common equity. Thus, use of composite ratios in cost analysis would distort the financing costs of most of the companies in the group.

Q. What causes the large variation between the composite capitalization ratios and the arithmetic averages of pipeline producers? A. The composite capitalization ratios represent a weighted average, while the averages I support are arithmetic averages. The reason for the large difference between these two is that the three largest producing pipeline companies in terms of dollars of capitalization, i.e., Tenneco, El Paso and Texas Eastern, have the lowest equity ratios and correspondingly the highest combined debt-preferred stock ratios. These three companies represented at December 31, 1966, almost half of the total capitalization in dollars of the 27 producing pipeline companies listed.

Q. Do you believe that the composite capitalization ratios for

[4261]

Independent Producers are representative of a typical Independent Producer. A. They more closely approximate the typical producer because the weighted averages are almost the same as the arithmetic averages. However, for purposes

[4261]

of comparison it is again necessary to use the 1966 capitalization ratio averages on Schedule 3 rather than the composite ratios on Schedule 5.

Q. Would you describe the range of capitalization ratios of independent producers and producing pipelines? A. Since a basic premise of Dr. Shaffner is that debt and preferred stock have lower financing costs, I will describe the range in terms of the equity ratios of the companies. The range shown for 1966 independent producer data on Schedule 3 is from 100% equity to 31.01% equity. The 1966 range of equity ratios for producing pipeline shown on Schedule 2 is from a high of 100% to a low of 22.33%.

Q. What conclusion can be drawn from these ranges in Schedule 2 and 3? A. It is obvious that the proportion of equity varies widely in the individual capitalizations of both producers and pipeline companies. Comparisons of the groups based on weighted averages conceal the fact that many pipeline producers have a capitalization more like the typical producer than the

[4262]

typical company in their own group. Thus, comparing the equity ratios of the individual independent producers on Schedule 3 to the average for all independent producers and the average for producing pipelines, it will be seen that six out of the thrity independent producers have an equity ratio closer to the pipeline group average than to the independent producer group average. It is also significant that the producing pipelines', and to a lesser extent, independent producers' equity percentages fall relatively evenly over the range. This indicates that the extent of the capitalization range is significant, and not merely the result of fortuitous extremes.

Q. What other factors do you think should be considered in comparing independent producers as a group with producing pipelines as a group with respect to the resulting return allowed on equity to each group, given the same overall return on investment? A. First, since the issue at hand pertains to the future exploration and development

[4174]

of natural gas production, it is necessary in calculating cost of capital of the two groups to use estimated future cost of debt and preferred stock. Producers cannot acquire and develop leases in the future with already invested dollars. Second, Dr. Shaffner mentioned in his

[4263]

testimony a study made by Chase Manhattan Bank regarding the nonfinancial "leverage" available to petroleum companies. It was estimated that, taking account only of the combined effect of production payments and long-term lease rentals, the composite debt ratio of the 33 petroleum companies group of the Chase Manhattan would be increased from 13% to close to 25%, or a difference of 12%. If we assume that this additional 12% of "operating leverage" is still available typical pipeline-to-producer ratios at December 31, 1966, would be 49.35% common equity for the producing pipelines as compared with 64.35% common equity for the independent producers. This comparison ignores additional leverage available to pipeline producers from these sources, but at most this could only amount to a fraction of a percentage of total pipeline capitalization.

* * *

[4266]

[Mr. Jones - Cross Examination]

Q. Are you the James C. Jones who previously testified on behalf of the Pipeline Production Group in this proceeding? A. Yes. . . . .

[4274]

Q. In computing the result of applying the regular area rate to pipeline production, have you given effect to the federal income tax aspects of pipeline production? A. No, but based upon the studies prepared by staff witness John Raymond, and the data appearing in his workpapers, the pipeline producer segment of the industry has a positive federal income tax expense in connection with production

operations. Since no allowance for federal income taxes is included in the regular area rate, and since my study does not reflect this additional cost, the actual return for pipeline producers would be lower than 6%.

[4275]

Q. Would that be true for each pipeline producer if all were given the same area rate? A. No, I doubt that it would, because when it comes to determining the impact of area ratemaking upon individual pipeline producers with respect to their future production, there are certain to be substantial variations. However, this is inherent in area ratemaking. The divergance in results will certainly not be limited to income taxes or rate of return, but will apply to virtually every component of the area rate.

* * *

[4277]

Q. With respect to the first issue, have you prepared an exhibit to determine whether there is a net spillover? A. Yes, I have done so. This is shown in Exhibit 70 (JCJ-7). This exhibit shows that the pipeline producer segment of the industry does not have a tax spillover but actually incurs a tax liability on its production operations, and this is so whether the pipeline producers are given the 12% rate of return applied to independent producers or the 6½% rate of return used for illustrative purposes by the staff witnesses. Page 1 shows the results of using a 12% rate of return and page 2 shows the results of using a 6½% rate of return.

Q. What is the source of the data which you used for the net tax deductions appearing on this exhibit? A. All of his data was taken from the Pipeline Production Questionnaire responses collected by the Commission's staff. The differences between these figures and those

[4278]

shown on Mr. Raymond's Schedule of tax deductions are attributable to the fact that he limited his analysis to stat-

utory depletion and intangible drilling costs, whereas the PPQ data contains a number of other tax items relating solely to production activities. My studies reflect those items, as well.

Q. How did you ascertain whether there is a spillover for the pipeline producer segment? A. At page 1983 of the transcript, Mr. Raymond defined spillover as "the excess of deductions attributable to the production function over the production return." I agree with this definition. I have already explained how I determined the deductions attributable to production, by using the 1962 data from the PPQ. The only remaining step was to determine the production return applicable to the same year.

Q. How was this determined? A. This material came directly from Mr. Raymond's workpapers which were identified by him earlier in this proceeding. Mr. Raymond applied a 6½% return to the production rate base of the 13 pipeline producers shown on Exhibit 70 (JCJ-7), constituting all of the major pipeline producers. In fact, the first column appearing on page 2 of this exhibit sets forth the

[4279]

$41,915,272 aggregate return on production rate base from Mr. Raymond's workpapers. Subtracting the production tax deductions from the production return shows that there would be a positive tax base on production activities amounting to $3,927,574, even using a 6½% rate of return. Thus there is no tax spillover for the pipeline producer segment.

Q. What is the result of this computation using a 12% return such as the Commission used in the Permian decision? A. This is shown on page 1 of Exhibit 70 (JCJ-7), and reflects a positive tax base of $39,393,092.

Q. What conclusion have you drawn from this study? A. I have concluded that the use of the regular area rate, which includes no federal income tax component, will certainly not be unduly generous to the pipeline producer segment since they have a positive tax liability on their production activities.

[4279]

Q. Mr. Jones, I believe you have made it clear that your demonstration of a positive tax for production activities of pipeline producers reflects the aggregate experience of the pipeline production segment. Does this mean that the staff recommendation of disparate treatment, reducing individual company allowances by spillovers, would have no impact?

[4280]

A. No, indeed. I am sure that there will be times in which some pipeline producers and affiliated producers, as well as some independent producers, will have production tax deductions which exceed their production return. This is most likely to occur for a particular producer in the years in which it conducts an extensive drilling program. Insofar as production activities are concerned, the income taxes are likely to be lowest in those periods I have prepared studies to demonstrate this condition, and to illustrate the drastic disparity which will result if one producer's tax loss is siphoned away, while another producer is permitted to utilize the tax loss which it incurs.

* * *

[Mr. Fields - Cross Examination]
[4327]

A. The question to be answered in this proceeding is not whether it is possible to derive average experience figures for pipelines, but rather whether such averages should be taken as representative of and appropriate for purposes of regulating the production of each individual pipeline.

In his attempt to see "how this group as a whole looked" Witness Zabel used the composited PPQ, The composited PPQ data was simply a summation of the reserve and production data for all the Group I pipelines. The result was to treat the composite as a single company to determine if the single company was underutilizing or "husbanding" its reserves. Such a method allows a relatively few companies with large reserve and production volumes to affect the

composited answer in such a way that the answer is not typical or representative of most of the individual companies.

Q. Would you show how such distortion has occurred in Witness Zabel's reserve-production ratio analysis? A. Yes, but first I want to show in a very simple hypothetical the possible distortion effect that can be caused by using the composite method. Assume that I had a group of five people and I wanted to know if in general this group has more income than the standard for the country. Further assume that the country standard was $5,000 per person. The incomes of the five people were:

$1,000	Mr. A.
1,000	Mr. B.
1,000	Mr. C.
1,000	Mr. D.
26,000	Mr. E.
$30,000	Arithmetic average = $6,000

[4328]

Now, I could appraoch the problem two ways. I could look at the individual data and draw a conclusion about the group, or I could look at the composite data and draw a conclusion about the group. By looking at the individual sata I would conclude that four out of five of the group were much lower than the standard income of $5,000, while one was much higher. Also, as an analyst, I would immediately conclude that an arithmetic average would be highly misleading. However, if I insisted that in order to form a conclusion about the group I would have to use composite data, I would come to the conclusion that the group had income above the standard. As is obvious, the exceptionally high income of Mr. E raised the indicated average to an amount 500% higher than the actual for the other four persons.

It should be obvious that an analyst can and should draw conclusions about the characteristics of a group by the evaluation of the data for the components of the group. If

[4328]

there is very little dispersion among the components, the analyst can conclude that the composite results are meaningful. However, if there is a high degree of disperstion and variation among the components, the composite results are misleading. Moreover, the results are even more misleading when the dispersions are not symmetrical, as in the hypothetical where four instances were below the average and one was above. Analysts should always concern themselves with the degree of variation and askewness within the group to form a judgment conclusion regarding the typicality and representativeness of a composite-based result.

Q. Did Witness Zabel concern himself with such analytical proprieties? A. No. If he had evaluated the individual company data, he would have

[4329]

observed how misleading his composite analysis was.

* * *

[4344]

A. Witness Jones' own data shows that there is substantial variation among the segments, as well as among the individual companies.

Q. How can such variation be observed? A. The most simple method, supplemented by the more formal analysis in my Schedules 19 through 21, is to casually peruse Exhibit No. 37 (revised). It is obvious by scanning the (P) designations that they are not distributed evenly throughout; many are at the high and low portions of the exhibit and very few in the intermediate portion. Such an appraisal

[4345]

shows that there were six pipelines in the first thirteen positions, and five pipelines in the last twelve positions, leaving only four pipelines for the sixty-one positions in between. In addition, only two pipelines were positioned between the

26th position and the 75th position. As I have already indicated, my more formal evaluation on Schedules 19 through 21 also shows a variation among the segments.

Q. What does your Schedule 19 show? A. Schedule 19 is based on Witness Jones' own quartile distribution of the cost data in his Exhibit 37 (revised). It shows that 59% of the independent producers were in the quartiles immediately surrounding the median, whereas only 41% were in the quartiles representing the "extremes". The positioning for the affiliates varied somewhat from that for the independents since 41% were surrounding the median, while 59% were in the "extremes". However, the variation is very noticeable for the pipelines, where only 27% surrounded the median, while 73% were in the "extremes".

Q. What does Schedule 20 show? A. The results shown above, as indicated on Schedule 19, suggest that pipelines as a group and independents as a group would have a different average unit cost. Such difference would indicate that there was variation among the segments despite Witness Jones' testimony to the contrary. Therefore, in Schedule 20, I have computed the weighted average cost for the three groups, using data exclusively from Exhibit No. 37 (revised). The results are:

15 Pipelines	22.13¢
17 Affiliates	13.74¢
54 Independents	13.99¢
86 Companies	14.93¢

[4346]

Thus, Schedule 20 shows a substantial variation between pipelines and independents.

Q. What does your Schedule 21 show? A. Schedule 21 is complementary to Schedules 19 and 20. It shows the average percentage of variation from the average cost for the three groups. The results are:

15 Pipelines	103.6%
17 Affiliates	27.4%
54 Independents	19.1%

[4346]

Thus, even though the pipelines have a higher average cost as a group, according to Witness Jones' data, the cost variation for the pipelines is very high. As Witness Jones testified, there are high and low pipelines, affiliates, and independents; however, Schedule 21 shows that the pipelines deviate more from the average than the other two groups.

Q. What are your conclusions regarding Schedules 19 through 21? A. Those Schedules show that there is substantial variation between the pipeline group and independent group data, as shown on Exhibit No. 37 (revised).

Q. Does your use of Witness Jones' cost data shown on Exhibit No. 37 (revised) mean you accept his "old gas" cost computations as unit cost-of-service determinations for pipelines? A. No. I merely used the cost computations to show that Witness Jones' own data controverts his testimony.

Q. Why are the cost computations for pipelines shown by Witness Jones on Exhibit No. 37 (revised) not unit cost-of-service determinations for pipelines?

[4347]

A. For several reasons. First, I believe it is presumptuous for anyone to feel that they have determined meaningful individual company costs without a detailed, involved study of each company taking into consideration the need for adjustments and special return requirement considerations. At Tr. 2,724, Witness Jones testified that his cost computations on Exhibit No. 37 (revised) would be fairly close to a cost-of-service type determination for each of the pipelines. However, Witness Jones' calculations included a 12% return for pipelines, despite the fact that the Commission generally has not allowed such a high return for pipeline production. In addition, his computation do not include a production tax component. Also, the royalty was implicitly computed by Witness Jones by the net working interest method, instead of on an actual-royalty-paid basis typically used in pipeline cost-of-service computations. Another problem is that in the Jones' computation, the joint product costs were

allocated instead of using the liquid credit method, more commonly used in pipeline cost-of-service computation.

Q. What is the purpose of Schedules 22 through 26? A. Schedules 22 through 26 of my exhibit pertain to Exhibit No. 23 of Pipeline Production Group Witness W. P. Anderson, and the related testimony of the group's witness, Merton J. Peck, who drew certain conclusions form Exhibit No. 23. At Tr. 681, Witness Peck referred to Exhibit No. 23 and pointed out that the success ratios for exploratory drilling for the three groups for the period 1955 through 1962 were:

Pipeline Producers	31.7%
Affiliated Producers	30.6%
Independent Producers	29.5%

At Tr. 682 Witness Peck stated:

[4348]

"The deviation from the overall average by any one group does not exceed 2.2%. To be sure, the small number of wells drilled in any one year by the two smaller groups of producers—Pipelines and Affiliates—means that their success ratio in any one year can and did deviate significantly from the industry average for that year."

My schedule 22, based on detail available from Witness Anderson's Exhibit No. 25, shows that the "deviation" was much higher for pipelines and indeed was surprisingly little for the independent producers and affiliated producers. However, I want to first emphasize that the lack of comparability in any year is an important feature. It should not be "averaged out" by using data for several years. After all, the success ratio has a noticeable effect on dry-hole costs and successful well costs. In the Opinion 468 method of cost determination, the dry-hole costs per foot and successful gas-well costs per foot are based on a single year. In this hearing now being held to determine, among other things, the propriety of prospectively applying the area rates

[4348]

to pipeline producers, it is exceptionally important to determine if there is comparability yearly and particularly in the more recent years.

* * *

[4357]

A. There is no evidence in this proceeding which indicates that the pipelines' future exploration and production costs should average out to the costs underlying the Commission's area rate determinations. Indeed, as long as pipelines continue to concentrate their production close to their systems, emphasize developmental drilling, and drill primarily for gas alone and at relatively shallower depths, their costs should continue to be different than independents' costs. Moreover, because of the regionalized nature of pipeline production and unique cost characteristics associated with each separate pipeline, costs for pipelines should continue to vary substantially *among* pipelines as they have in the past.

Q. What indication do you have that pipeline costs vary among pipelines?

[4358]

A. My Schedules 35 and 37 show the substantial variation. I am not taking the position that the cost determinations in the three cost arrays on those schedules are precise. However, the cost computations for the three arrays were made by two separate parties, the FPC Staff, and the Pipeline Production Group. Therefore, while I do not accept the cost determination for each pipeline as an individual company cost-of-service computation, I believe the dispersions based on such diverse cost computations are meaningful indications of cost variation among pipelines. As can be seen, there is no such thing as a meaningful average or general cost that describes pipeline costs. When Witness Deutsch states that pipeline costs are higher than independents, he misleads us since pipeline costs cannot be generalized.

Q. Can you present evidence that pipeline costs are not conducive to a general description of being either high or low? A. Yes. In the above quote from Witness Deutsch's testimony at Tr.620, lines 1 through 17, Witness Deutsch compared *national* depreciation, depletion and amortization costs for pipelines with those costs for independents and affiliates combined. Such a comparison is certainly illogical, since I have demonstrated in Schedule 7 that pipelines concentrate production in different areas than other producers. If we use the same A.F. Bass Exhibit Nos. 53-J (Item A By Reference) and 54-J (Item B By Reference) that Witness Deutsch used, but compare pipeline costs in a particular area with independents' and affiliates' costs in *the same area*, we see Witness Deutsch's statement is misleading, as indicated by the following:

[4359]

Area	D.D. & A. - - Cents Per Mcf: Independents and Affiliates	Pipelines
Area 14	1.36¢	.64¢
Area 16	2.79	1.26
Area 17	3.38	10.47
Area 19	1.30	.70
Hugoton-Anadarko Combined	1.74¢	.76¢

As can be seen, D.D. & A. costs are substantially lower for pipelines in the combined Hugoton-Anadarko areas. Also, it should be noted from my Schedule 6, the 4 areas shown accounted for 38% of the total pipeline production in 1965. Of course the above compilation shows that the D.D. & A. costs in Area 17 *were* higher for pipelines. However, as shown in my Schedule 6, only .2% of the total pipeline production was produced in that area in 1965. In addition, I should point out that the data in Witness Bass' exhibits show that D.D. & A. costs in the Texas Gulf Coast, Areas 7, 8

[4359]

and 9, were higher for pipelines. However, my Schedule 6 shows that only 2.5% of the total pipeline production was produced in those areas in 1965.

* * *

[Witness Johnson - Cross Examination]

[4425]

* * *

A. Well, let me get at it this way. When you say does more expensive capital has to be used, as my exhibit shows, the group of independent producers here have raised debt capital as cheap or more cheaply than a group of natural pipelines. The independent producers are engaged predominantly in the production business, presumably, and the pipelines are engaged in the transmission business. So if you are speaking of about a component of capital I am not sure I can say "yes." If you are speaking of overall capital requirements, then I think I am saying that due to the riskier nature—and by "riskier" I mean the lower possibility, the lower odds of succeeding in the venture—then I think the mix of capital, as between the less expensive debt capital and more expensive equity capital, must follow that riskier nature of the business.

Q. Mr. Johnson, if a company uses high cost capital for production, any way you arrive at this, must it not, of necessity have less high cost capital to invest in its operations? A. I don't think I understand your question, sir.

Q. Well, if we assume overall capital is at a given rate, and if a company uses—A. I am sorry, what kind of a company is this we are talking about?

Q. An integrated company that produces as well as has a

[4426]

transmission function. And if it uses high cost capital to finance its production operations wouldn't it necessarily mean that less high cost capitals were used to invest in its operations? A. I think you are talking about pure arith-

metic, aren't you? If it is an integrated company, if we attempt to segregate the capital of that company, of that dedicated to a certain function rather than another function, if it has dedicated high cost capital to one of the functions it must have low cost capital dedicated in order to reach the average cost of the company's capital.

Q. Do you agree investors invest in the company as a whole and not in isolated parts of the company's business? This is generally a statement that was made by Dr. Shaffner.

A. I will agree that investors look at the company as a whole, and not to any specific piece of its business.

* * *

[Witness Jones - Cross Examination]

[4500]

MR. SHIBLEY: Excuse me, are not included in the .89 cents. Do you know whether they are included in the other part of the exhibit, that is, the Staff's and AGD exhibits?

THE WITNESS: Yes, they are included in the Staff and the AGD cases, along with the pipeline production data.

MR. LEITHEAD: Well, they are included in that other data, along with the other independent producers, is that correct?

THE WITNESS: Yes, that is correct.

MR. LEITHEAD: In fact, if my understanding is correct, the Commission in Permian Basin and some of the other cases—well, the Commission has not decided the other cases—but in Permian Basin, at least, they didn't distinguish between pipeline production and affiliated production and independent producers' production. Those parties made respondents to the proceedings were included in the new gas cost computation that you have shown in your exhibit, is that correct?

[4501]

THE WITNESS: That is correct. All producers, I think, whether they be pipeline, affiliate, independent, small pro-

ducers, were included in the basic data, the Census Bureau data, and the drilling data, and so forth.

MR. LEITHEAD: Your Honor, I do apologize for interrupting Mr. Wheatley's cross-examination, but I do want it to be clear on the record that the affiliated producers are not included in the computations contained in his exhibit, and whether they are or not, I am not sure that Mr. Wheatley is really making the point, because, as I understand it, the pipeline production group's contention is they are merely trying to show they should be entitled to the same rate the producer is entitled to. Whatever the rate of return, whatever the individual cost involved, may be included in the determination of that ultimate area rate, really they are not too concerned with.

On the other hand, I am concerned with the Staff's position that area rates should be reduced for income tax considerations and for rate of return considerations.

If there is going to be any implication in this record through Mr. Wheatley's cross examination that affiliated producers–affiliated producers being Cities Service Oil Company and Columbia Fuel Corporation–are taking the position they should get something less in the way of credit, and something less in the way of a rate of return as a result, then I want it to be clear that that is not the position we are taking.

[4502]

We want the same rate of return on our production properties. We want the same tax treatment and the same treatment across the board as the independent producers are receiving.

I say that subject to the understanding that that treatment is not too good.

MR. FLETCHER: Mr. Examiner, that is the same position our company has.

It contends that it is in fact an independent producer, and that it being joined here is inappropriate.

MR. JABLON: Your Honor, I am not going to take the time to debate the merits of the affiliated cases.

Just to make the record clear, I wish to point out some of the data used in the area rates to which Mr. Leithead referred variously included pipeline producers, pipeline affiliates, or independent producers in various combinations, and the specifics may have been misleading.

MR. WHEATLEY: Yes, Your Honor, I think if there is any ambiguity in what is included in the exhibits and Mr. Jones' testimony as to whether affiliates are or are not included in these figures, that that ambiguity is inherent in the pipeline production's presentation and not in my questions.

I am questioning him on what he did.

MR. LEITHEAD: Well, I must apologize to Mr. Wheatley, as I just wanted the record to be perfectly clear, and I believe it is now, that affiliated producers are not included in the

[4503]

computations that Mr. Jones has made in his exhibit. I think Mr. Wheatley will agree to that.

Is that correct?

MR. WHEATLEY: I didn't prepare the exhibit so I can't reply as to what–

MR. LEITHEAD: In view of the witness'–

MR. SHIBLEY: I don't believe you should have any hesitancy about agreeing to it, Mr. Wheatley. It says right there on it.

MR. WHEATLEY: Apparently Mr. Leithead has a problem with it, Mr. Shibley.

MR. LEITHEAD: Mr. Wheatley, I asked Mr. Jones earlier, and I will ask him again, whether or not affiliated producers are included in the computations in the exhibit to which you have referred in your question–in the pipeline computation.

THE WITNESS: They are not included in the adjustment for the net liquid credit.

[4503]

However, as has been stated before, they are in all the other components to the extent that nationwide data was used for all producers.

BY MR. WHEATLEY:

Q. There is only one figure in both columns that doesn't include the affiliate producers, is the point. Every other figure on that exhibit includes them? A. That is correct.

MR. LEITHEAD: Now, Mr. Jones, let's think about that

[4504]

question very carefully, because I don't believe Mr. Wheatley has phrased it in the way I would have. I am sure of that.

Let's refer to Exhibit 69. Is that the exhibit we are referring to?

THE WITNESS: Yes.

MR. LEITHEAD: Specifically, let me ask you this with respect to the first figure, or the figures shown—

MR. REIFSNYDER: Mr. Examiner, I hate to interrupt. I can't hear Mr. Leithead, but I am very interested in this.

MR. LEITHEAD: I will speak up, Mr. Reifsnyder.

Let's refer specifically to the category of exploration and development cost shown on Exhibit 69, page 1 of 2, and to the second column, where you show a figure of 1.67 cents for dry holes. Do you see that figure?

THE WITNESS: Yes, sir.

MR. LEITHEAD: Does this figure include affiliated producers dry hole costs?

THE WITNESS: Yes.

MR. LEITHEAD: Does it include independent producers' dry hole costs?

THE WITNESS: Yes, sir.

MR. LEITHEAD: All right, then, is my understanding correct that you have used total independent producer, pipeline producer and affiliated producer costs in determining each of the unit cost figures shown in the second column on that page of your

[4505]

exhibit?

* * *

[4512]

* * *

THE WITNESS: I don't believe there was any need to make a special study other than what has already been done, where you single out several items, but you accept all the rest of them.

The production costs, production investment costs, may be higher. The depreciation, depletion and amortization costs may be higher for pipeline producers in the future. Instead of being four cents, they might be eight cents.

It doesn't make any difference when you are using an industrywide rate base, but you are applying individual company data to it.

* * *

[Witness Freitag - Cross Examination]

[4610]

* * *

BY MR. JABLON:

Q. Well, would you give us both Tenneco Oil and Tenneco Corporation, together? A. Are you sure we are talking about the same date now, 1966?

Q. Yes, sir. A. I got my–I think my source may not be Moody's, if that is your source, but I computed it and came up with the 74 percent equity and 26 percent debt for Tenneco Oil Company.

Q. And what is Tenneco Corporation? A. It would be 70 percent equity, 30 percent debt, approximately.

Q. Thank you, sir.

Does Tenneco, Inc., also own Tennessee Gas Pipeline Company? A. As I stated in one of the previous answers, it is a division of Tenneco, Inc. It is one and the same corporation, practically.

[4610]

Q. Is the cost of debt financing less than that of equity financing? A. In terms of what, Mr. Jablon?

Q. In terms of money.

[4611]

MR. McCORKLE: Gold.

MR. McMILLEN: For whom?

BY MR. JABLON:

Q. For the Corporation. A. To the extent that you are able to take interest as a tax deduction, I think there is some lesser cost related to debt.

Q. Apart from the interest deduction, would you consider earnings which a company retains part of the cost of equity financing? A. Yes.

Q. If Tenneco, Inc., should earn more than the amount necessary to cover the interest on its debts, and payments on its preferred stock, would this mean that any additional profits generated by the assets of the company would be shared by the common stockholders?

MR. BROWN: May I have that question read, Your Honor?

(Question read.)

THE WITNESS: If it were paid out in dividend they would share in it immediately. To the extent it was reinvested in the business they would have to look to some future date, possibly, to share in it.

BY MR. JABLON:

Q. But it would accrue to their benefit? A. It would accrue to their benefit.

* * *

[4983]
[CROSS-EXAMINATION]

[Mr. Wilhelm - Cross Examination]

[BY MR. JABLON]

I would say based on my knowledge it would be hard to estimate what an independent producer could do in the past.

I would base any assumption on what has happened in the past three or four or five years, and for a fact independent producers have, during that period of time, increased the amount of debt financing.

MR. ROSS: Mr. Wilhelm has a soft, Southern voice. I think we are going to have trouble.

BY MR. JABLON:

Q. Just if I may attempt to sharpen your last answer. Is it your opinion that you don't know whether this trend will continue, or based on recent history that you would expect this trend to continue? A. I would expect the trend to continue.

[4990]

STAFF WORKPAPER SHOWING IMPORTANCE OF TENNECO, EL PASO, TEXAS EASTERN, AND PANHANDLE AS PRODUCING PIPELINES

IA. Percent of own production to total natural gas pipeline company production as reported in *Sales By Producers of Natural Gas to Interstate Pipeline Companies* - 1966, Table 7, pp. 413-414.

	Volumes	%
Tenneco[1]	87,782,371	8.7
El Paso	207,663,010	20.7
Texas Eastern	62,768,168	6.3
Panhandle Eastern	103,768,103	10.3
Total 4 Companies	461,981,652	46.0
Total All Companies	1,004,227,930	100.00

[1] Tennessee Gas Pipeline Corp., Division of Tenneco

B. Percent of own production of gas production to total natural gas pipeline company production for 1962 as reported in Pipeline Production Questionnaire, Schedule 18.

	Volumes	%
Tenneco[2]	24,599,321	4.02
El Paso	88,061,333	14.39
Texas Eastern	55,313,516	9.04
Panhandle Eastern	76,262,365	12.46
Total 4 Companies	244,236,535	39.9
Total All Companies	612,010,882	100.00

[2] Tennessee Gas Transmission Co.

IIA. Gross Investment, Exhibit 54, Schedule 3, Sheet 1.

	$	%
Tenneco[1]	$ 191,815,216	21.6
El Paso	267,970,254	30.2
Texas Eastern	70,105,129	7.9
Panhandle Eastern	21,837,785	02.5
Total 4 Companies	$ 551,728,384	62.2
Total All Companies	$ 886,761,622	100.00

[1] Tennessee Gas Pipeline Co.

B. Net Investment, Exhibit 54, Schedule 4, Sheet 1.

	$	%
Tenneco[2]	$ 181,133,217	28.7
El Paso	234,959,675	37.2
Texas Eastern	37,041,141	5.9
Panhandle Eastern	15,418,207	2.4
Total 4 Companies	$ 468,552,240	74.2
Total all Companies	$ 631,638,283	100.00

[2] Tennessee Gas Pipeline Co.

[4991]

Return on Equity for Tenneco, El Paso, Texas Eastern and Panhandle Eastern. According to Maurice F. Wilhelm, Jr., Exhibit No. 67, Schedule 2

Tenneco

56.95	x	4.44	=	2.53		Debt
17.39	x	5.05	=	0.88		Preferred
25.66	x	12.04	=	3.09		Equity
				6.50		Overall

El Paso Natural Gas Co.

68.36	x	4.93	=	3.37		Debt
9.20	x	5.05	=	0.46		Preferred
22.44	x	11.90	=	2.67		Equity
				6.50		Overall

Texas Eastern Transmission Corp.

64.81	x	4.85	=	3.14		Debt
12.86	x	5.31	=	0.68		Preferred
22.33	x	12.00	=	2.68		Equity
				6.50		Overall

Panhandle Eastern Pipeline Co.

60.80	x	4.18	=	2.54		Debt
6.25	x	4.54	=	0.28		Preferred
32.95	x	11.17	=	3.68		Equity
				6.50		Overall

[4992]

MR. ROSS: May I inquire before counsel addresses a question to Mr. Wilhelm as to the derivation of certain figures on one of these sheets?

The sheet headed "Return on Equity." I apologize for doing this, but I would like to clarify the record. I see that

you have a capitalization ratio of the four companies, and you multiply them by certain percentages. Where are those percentage derived?

MR. JABLON: Exhibit No. 67, Schedule 2, I believe.

THE WITNESS: Could I be looking at a copy of these schedules?

MR. ROSS: Is the equity percentage simply a mathematical derivation, derived from taking the debt and preferred stock percentages which appear on Schedule 2 and assuming 6.5 percent return?

MR. JABLON: Yes, I believe that is the case. Also, for clarity, I would point out that the investment figures are gas-only on this sheet.

The investment figures shown on Staff Work Papers Showing Importance of Tenneco, El Paso–

MR. ROSS: You are now talking about the other work paper? There you have investment for gas-only?

MR. JABLON: That is correct.

Well, gas lease.

MR. ROSS: Does Mr. Wilhelm have a copy of these?

PRESIDING EXAMINER: Yes, he has, two were submitted to him.

MR. RICHTER: Mr. Jablon, on the second work paper showing the cost–the Staff Work Paper Showing the Importance of Tenneco, El Paso, Texas Eastern and Panhandle as Producing Pipelines, under IIA you have Tenneco, and under A and B upi jave Tenneco and show figures in both instances for Tenneco. I assume those are the ones Mr. Bass had in his Schedule 54, and they are unadjusted for Ship Shoals and the off-shore leases where we have production?

MR. JABLON: That is correct, and the Footnote 2 on IIB was left out, but that also refers to the data for Tennessee.

The reason for the use of the word "Tenneco," is, I was conforming to the witness' terminology.

MR. RICHTER: I might also point out they are apparently having a new form for Tennessee. In the first foot-

note they have Tennessee Gas Pipeline Corporation Division of Tenneco, then they have Footnote 2, Tennessee Gas Transmission Company, and footnote, Tennessee Gas Pipeline Company.

We may be an integrated company.

MR. JABLON: I was simply using the names of the companies which appeared in those sources, and the names from the sources vary.

My purpose was simply to get a range of commonly used data to indicate the importance of the companies, and rather than

[4994]

showing the witness Form 2, and asking him to compare the volumes and take it subject to check, I have compiled what I believe to be the representative sources.

MR. WATSON: So that the record will be clear, this Tenneco you speak of here, you are not speaking of Tenneco Oil Company, are you?

MR. JABLON: I am referring to whatever the footnotes refer to.

The reason for my use of the word "Tenneco" is that was what the witness had used in his testimony.

MR. ROSS: Mr. Jablon, while our witness is looking these over, let me ask you another question.

Have you made the computations which would be equivalent to the computations on your "work paper showing importance" of the percentages which would result from removing the in-place purchase volumes?

MR. JABLON: No, I have not, Mr. Ross, but I assume that can very easily be derived from–I don't remember the exhibit number, but you have an exhibit showing that data.

* * *

[5013]

THE WITNESS: I have not made a cost of capital calculation for non-producing pipelines. However, I have de-

[5013]

termined what their capitalization ratios are in comparison with the capitalization ratios of the producing pipelines.

* * *

[Witness Smith - Cross Examination]

[5275]

Q. Apart from the tendency of any group of companies to disperse around a norm, or mean, do you have additional reason to believe that history well could repeat itself? A. I meant by that statement that I think that in the future you will have higher cost and lower cost production by pipelines.

I think the application of an average cost to pipelines simply does not appear to be rational on the basis of their experience.

I think putting it into relationship with the past experience of pipelines, and the past method of regulation of pipelines, putting them on an average basis is going to have a tendency to hurt some consumers so far as the price is concerned that they pay for gas.

It might give a benefit to others, but there would be many problems of administrative and perhaps legal types that would have to be overcome before we could be sure that the highcost producer would not be able to get his costs, notwithstanding an attempt to use an average cost as a basis for an area rate.

I think it is a real problem. I think it is one of the most critical problems in this whole proposal.

Q. By that last clause were you referring to the problem of special exemptions? A. Yes, special exemptions, and the fact that Mr. Deutsch's

[5276]

testimony has touched upon this, indicating, as I understood his testimony, certainly a willingness to make exceptions in perhaps facing the practical problem that they would absolutely be necessary.

Q. Would you refer to your testimony at transcript 4200, which is the same page, line 22, and would you read that

carefully through page 42-1, the following page, up through line 6?

MR. LEITHEAD: Where does line 22 begin?

MR. JABLON: It is the full paragraph, starting at the bottom of the page.

THE WITNESS: Yes, I have that in mind.

BY MR. JABLON:

Q. Now I am going to ask you a general question, but I would very much like your opinion on it.

Would you assume that the Examiner and Commission agree with you and decide to continue cost of service regulation for producing pipelines and pipeline affiliates to whatever extent they are encompassed by your regulation.

Referring to the testimony which I have just cited, would you have any recommendations, or modifications, which you would recommend to cost of service pricing as it is currently conducted in order to protect consumers from specific instances of excessive cost incurrence?

MR. FLETCHER: Mr. Examiner, I think I would object to that. That is just pure speculation. It is not tied down to

[5277]

anything in this case.

* * *

[5340]

Q. In other words, you would assume the producer in

[5341]

future years would earn from its exploration in future years the return which you set on the production rate base; is that correct? A. No. I wouldn't necessarily assume that at all. I would assume that the producer is to be allowed a return, and under cost-of-service regulation. If he is allowed that return the presumption is he is going to have revenues that will permit him to earn that return–at least that is the theoretical aspect of it.

[5341]

Q. As I understand your last answer, your answer to my immediately prior question, is "yes"? A. Well, I like to put it in my language because I don't understand yours. You used the word "future," and that could have a far different connotation than the prospective matching of cost and revenues that takes place in a rate case, too, because this is certainly not into the indefinite future. It is subject to reexamination at some reasonable time in the near future, perhaps, even. It is purely prospective, rather than being future in an unlimited sense.

Q. Would you turn to transcript 4200, please. A. Yes, sir.

Q. About the middle of the page, Mr. Smith, you have the sentence which begins "If history repeats itself"— A. Yes, sir.

Q. —"as it well could, there would be no justification

[5342]

for granting the lower cost producers windfalls at the expense of consumers," and so forth.

It was not clear to me what the reference you were making in the phrase "if history repeats itself" was. A. I would normally anticipate there would be both what we might term in a general sense, for comparative purposes, high and low cost producers. I mean by that, producers who would experience costs somewhat less than the average, and those who experience costs somewhat higher than the average.

Q. Is this the average of all producers? A. I was addressing myself to pipelines, because I show no producers in that exhibit, except pipeline producers.

Q. Is it your opinion, Mr. Smith, pipeline producers have had different production costs from other producers on average?

MR. GOLDBERG: May we have that question again, please?

(Question read.)

MR. GOLDBERG: By "other producers," does counsel mean producers other than pipeline producers?

MR. ROSS: Yes, sir.

THE WITNESS: Over what period of time?

BY MR. ROSS:

Q. Over whatever period of time you have looked at it, Mr. Smith. A. Well, I haven't made any extensive study of average costs of producers. I am not too convinced that average costs

[5343]

have any real significance.

Q. Take the cost components in your Exhibit 59, D.D. & A., for example, and look at the averages which you are comparing to the equivalent figure in the Commission's cost determination in Permian Basin. Do you find that that average is far from the independent producer average cost component, or is it close to it? A. I think as I pointed out in my testimony, that for D.D. & A. the averages of the pipeline group, and the producers in toto, are about the same, for D.D. & A. on the average. Whether this is an accident or whether it is significant, I really don't know.

Q. You used the term "windfall" in your answer on transcript 4200. Would you please explain what you meant by that term as you used it? A. Well, a "windfall" to me would mean granting something to a regulated company so that it could collect revenues which were unjustified from the standpoint of the costs that it would incur. If it has the protection, or whatever you might want to term it, of the regulatory process, in accomplishing something like that to me that would be a "windfall" or you could equate it with an unreasonable rate of return on a cost basis.

Q. So an independent producer that received a price based on an area rate which very substantially exceeded its cost plus a reasonable return would be earning a windfall in your definition?

[5344]

MR. JABLON: May I have the question, please?

(Question read.)

THE WITNESS: I think that that possibility does exist in the group pricing, even with independent producers. Of course I was not addressing myself to the problem of the producers, I was addressing myself to the problem of the pipeline producers, which is an issue in this case, where there is a proposal to change a method of regulation that pretty well assures producers would not receive a windfall at the expense of consumers, over to a method which might have inherent in its mechanism that possibility.

Now, I was not directing any attack on independent producer rate making here, although since I said a regulated company I assume that would include independent producers under area rate regulation.

* * *

[5351]

Q. Yes, sir. A. There was a lot of doubt, or at least if there was jurisdiction it was not exercised.

So that ought to tend to prevent a recurrence of where expenditures for reserves in-place may have been excessive, or at least looked excessive on their face.

Q. You are talking here not about a disallowance but about the Commission in effect pricing the reserves? A. I don't understand.

Q. A little bit different concept, although related.

MR. REIFSNYDER: Could I have that question read back?

(Question read.)

THE WITNESS: I don't think I understand that.

BY MR. ROSS:

Q. Well, the disallowance would involve not permitting the pipeline producer to claim as a cost all or part of a purchase price. That is correct, is it not? A. Yes. If it came to the question of disallowance, presumably that could be one aspect of it.

Q. This is peripheral to my inquiry, Mr. Smith. Let me move on.

You said in your answer to my question asking you to give an example of where you would recommend disallowance you had two concepts in there.

[5352]

One, it applies to excessive need; and, two, an excessive price or unreasonable price, as I recall–I don't recall your exact words.

Of course that is the basic problem, is it not, that the productior management has to determine ahead of time what the Commission will consider to be its supply in excess of need, and a price which is considered to be unreasonable under cost of service standards? A. Yes. It is a difficult problem, and there have been many imponderables in it.

Q. Let me give you a hypothesis, Mr. Smith.

Lets' suppose I am a pipeline producer and I purchase from the Federal Government some leaseholds off the East Texas coast for about 10 million dollars, and I enter into a joint venture with a number of independent producers and we go off shore and we explore and we drill up those leaseholds, and we find that our geologists, although they were competent and did everything that they should do according to the tenets of their own profession, actually were wrong, that this formation didn't extend out into the area in which we purchased these leaseholds.

The pipeline producer which I am referring to has about 75 million dollars in that rat hole, and they are never going to get some gas. They found some gas down there, but not enough warranting running the pipe out to the formation and producing in commercial quantities.

[5353]

That is 75 million dollars in the cost of service, out-of-pocket to their consumers and their customers. What

[5353]

would be your recommendation as to disallowance? A. You say they never found any gas?

Q. If they didn't find enough to warrant their running a pipe out to it to produce it. A. Then they do have, you say, 75 million dollars of investment?

Q. Including their original lease payments, and their exploration, including their geophysical, geological costs, they have 75 million dollars sunk in this worthless project which they hoped would produce a very large volume of gas, but didn't. A. Well, of course what you are saying doesn't mean they have 75 million dollars in investment, isn't that right?

Q. They have 75 million dollars in nothing–expenses. A. Well,–

Q. Will these costs, however they are regarded for accounting purposes, be disallowed, or will the pipeline in the test year be entitled to claim them in its cost of service? I am asking you for your recommendation to the Commission, just to get an idea of your own thinking on this disallowance. A. Well, I think you have the problem stated so that it is not in very good perspective. I am trying to find out what you are really trying to tell me. I think maybe I understand it

[5354]

or I can pose mu understanding of it.

I take it this is something that has taken place over a period of several years–the incurrence of these costs.

Q. You can assume either for the purpose of the example it had all taken place in one year, or you can assume it has been taking place over a number of years, and we are talking about an averaging of costs for cost of service for test year purposes.

MR. JABLON: May I have that last clause read back?

(Record read)

MR. JABLON: In other words, Mr. Ross, if appropriate, when you say "averaging", if appropriate, you would allocate some of those costs to the test year, however applicable?

BY MR. ROSS:

Q. That is right. Let's assume you have 75 million dollars of costs of the kinds I have described in your test year however they got there. A. Well, the thing that is missing in your formula, of course, is that I can't tell–I don't think you have indicated the extent to which those costs prior to this test year have actually been paid for and recovered through the rate structure at that time, or, where posiible through the earnings structure of the company.

I don't think the problem can be placed–I don't think it is answerable without knowing what the assumption is as to

[5355]

that.

In other words, does this company have an allowance for exploration in its cost of service?

Q. Let's assume the company did not have an allowance for exploration in its cost of service of such a size as to anywhere begin to cover these costs. A. You are almost on the verge of mismanagement right there.

Q. In other words, you are saying if they go off shore and they take this risk of finding nothing where they don't have the allowance in their cost of service, that they are almost on the verge of mismanagement? A. I am saying that a producer, or a pipeline company, let's put it that way–because this was a pipeline we were talking about–if they go into exploration activities without having obtained an allowance for that exploration activity in their cost of service, it seems to me that that is a very improvident act, because exploration activities, under the Commission's accounting rules, under its rate-making procedures, are presumably financed out of revenues–I mean exploration losses, such as dry holes, and the other expenses that are incurred to carry on an exploration program.

Now, I don't know of any principle of rate making that would require the Commission to make a provision to indemnify a company for past losses at any given point of time.

[5356]

Now, if there is a future drilling program set up and an allowance made for it in a cost of service that has the approval in the rate structure, prospectively, I can see where the cost of service could result in a given situation of that kind of some exploratory losses being passed on to consumers and no gas being obtained in that particular situation.

Q. Mr. Smith, isn't the problem the chicken and egg problem?

You said they would be imprudent if they explored and developed without a component in their rate structure. The only way they can get such a component in their rate structure is to have such expenditures in the test year, so that is axiomatic. A. I don't know whether you have made a correct axiomatic statement or not.

I have never assumed that what you said is axiomatic.

I would agree that it is relevant.

Q. I will accept your agreement that it is relevant. A. But the extent it is relevant is not necessarily inflexible, or dogmatic.

* * *

[5400]

Q. Then, with reference to your testimony at 4245, lines 4 to 11, and specifically lines 5 to 11, would you elucidate on what standards you would apply to determine whether there has been inefficiency or imprudent expenditures as you used the term on line 7 through line 8?

* * *

[5401]

THE WITNESS: Well, I believe the first step would be to determine the cost of production, certainly at least on a field-by-field basis with respect to the pipeline producer, and then to determine the unit cost of production with respect to each field. That would give you an indication there as the to variations in costs between fields.

You would also have available the costs of gas which was purchased from those fields from independent producers, assuming that there are purchasers–there may not be in all of the fields but there would be in some of the fields. That would be my first comparison.

Now, suppose you found that in one particular field there was a great disparity in costs, or unit cost, as compared with other fields. Then you would start investigating as to what are the reasons for that cost, excess cost. You would then

[5402]

inquire into the acquisition of the leases. In other words, you would have a breakdown of that cost, how much of it was related to the bonus paid for the leases, how much was D. D. & A. and other direct costs of production from that lease. You would make a cost analysis to find out where they are then you start to find out what are the reasons for that. You may want to look at the reports of the geological department, to management recommending certain activities in the way of drilling. It may develop that you have a situation where, for example, you only had a partial year production from that particular field, although you might have a full investment cost for that field.

Are there out-of-period items involved. Is the field fully developed or only partially developed, and what are the prospects for future development that are going to bring the unit costs down. If you found the drilling costs were way out of line from what would normally be expected, based on what drillers are bidding on drilling contracts, you might want to look into that to see whether the drilling contract wasn't let to the brother-in-law of the president, for example, at an exorbitant cost or something like that.

Those are the sort of things, or sort of analyses, that should be made to determine whether or not an expenditure was

[5403]

imprudent, extravagant, and depending on what you find you would make a recommendation as to appropriate treatment. I don't think you can look at simply a rate or cost that somebody else has incurred maybe thousands of miles away in a production venture, and say "ipso facto, means this particular producer is inefficient, or has incurred imprudent costs."

[5420]

MR. JABLON: The parties with whom I have had discussion have agreed, first, that there may be disagreement among the parties and/or witnesses as to whether there is or would be a positive or negative tax on pipeline or independent producer production activities.

Second, the parties with whom I have had discussions are in agreement that an actual positive or negative tax liability can not be determined from the data available in this record, and I underscore "the data available in this record." And of course I am referreng to Phase I.

Now, with regard to those two premises, if they are generally accepted, it would clearly limit the use of both John Raymond's Exhibit No. 1, with reference to the tax schedules, and the rebuttal exhibits addressed thereto for

illustrative purposes, whether to show that there can be tax deductions of significance, or, on the contrary, that there can be offsets going in the other direction, but that these exhibits could not be shown to demonstrate that either there would be a positive or negative tax in direction or in amount for rate-making purposes.

[5431]

MR. ROSS: Mr. Examiner, speaking for the Pipeline Production Group, I suppose if we were to state an agreement, if you can call it that, which Mr. Labon has stated, we would do it in somewhat different words and with somewhat different emphasis. However, we are generally in agreement with what Mr. Jablon said.

I think it has to be recognized in talking about the issue of whether there will or will not be a positive tax on pipeline production, we are talking about the issue of whether expenses, revenues from leases which have not yet been acquired at some time in the future, will generate a positive or negative tax. As to that issue if Your Honor were gifted for it you might be able to decide it, but I don't know that you can decide it on the basis of any evidence that anyone could introduce in this proceeding without foresight, miraculous foresight, I should say.

We don't know what pipeline producers would do in the future and obviously what they do will determine whether or not their production yields a positive or negative tax. I think that the actual basis which Mr. Jablon has suggested for leaving this evidence in the record, subject to a general understanding that the parties will not argue that the record establishes for the future a positive or a negative tax, is a fair disposition of the controversy.

PRESIDING EXAMINER: Mr. Brown.

MR. BROWN: Yes, Your Honor. On behalf of the Consolidated

[5432]

Gas Supply Corporation, I certainly want the record to reflect my agreement that insofar as the pipeline producing aggregate, industry as a whole, is concerned, you can't determine on the basis of any evidence in this record whether that industry has in fact a positive or a negative tax liability. And I woudl support Mr. Ross' statement.

[5433]

PRESIDING EXAMINER: Who else wishes to be heard on this subject?

MR. RICHTER: I just want to add my agreement with Mr. Ross and Mr. Brown, Mr. Examiner.

* * *

[5724]

Exhibit 5

Producing Pipelines Named Respondents to All Area Questionnaire and Pipeline Production Questionnaire

Line No.	Code Nos. (a)	Company Name (b)
		Producing Pipelines Included in All Area Questionnaire Composite
1.*	026100	Arkansas Louisiana Gas Company
2.	156300	Colorado Interstate Gas Company
3.	237200	El Paso Natural Gas Company
4.	407750	Humble Gas Transmission Company
5.	449530	Kansas-Nebraska Natural Gas Co., Inc.
6.	455100	Kentucky West Virginia Gas Company
7.*	576300	Mississippi River Fuel Corp.
8.*	597500	Mountain Fuel Supply Company
9.	610870	Natural Gas Pipeline Company of America
10.	616100	New York State Natural Gas Corp.
11.	658900	Panhandle Eastern Pipeline Company
12.	813580	Southern Natural Gas Company
13.	861200	Tennessee Gas Transmission Company
14.	864700	Texas Eastern Transmission Corporation
15.	897200	United Fuel Gas Company
		Not Included in All Area Questionnaire Composite but Named Respondents to Pipeline Production Questionnaire
16.	032100	Atlantic Seaboard Corp.
17.	140300	Cities Service Gas Co.
18.	185900	Cumberland and Allegheny Gas Co.
19.	393700	Hope Natural Gas
20.	426800	Iroquois Gas Company
21.	541300	Manufacturers Light and Heat Co.
22.	576330	Mississippi River Transmission Corporation
23.	635900	The Ohio Fuel Gas Company
24.	672650	Pennsylvania Gas Company
25.	884200	Trunkline Gas Company
26.	897450	United Natural Gas Company

* Respondent to All Area Questionnaire but not to Pipeline Production Questionnaire.

[5725]

Pipeline Affiliates Named as Respondents to Pipeline Production Questionnaire

Line No.	Code Nos. (a)	Company Name (b)
1.	018260	Anadarko Production Company
2.	141000	Cities Service Oil Company
3.	156500	Colorado Oil and Gas Company
4.	158000	Columbian Fuel Corporation
5.	237255	El Paso Products Company
6.	477000	La Gloria Oil and Gas Company
7.*	506870	Lone Star Gathering Company
8.	507000	Lone Star Producing Company
9.	698500	The Preston Oil Company
10.	860900	Tenneco Oil Company
11.	865500	Texas Gas Exploration Corp.
12.	895700	Union Producing Company

* Not an AAQ respondent.

[5726]

Independent Producers and Pipeline Affiliates
Included in All Area Questionnaire Composite

Line No.	Code Nos. (a)	Company Name (b)
1.	017000	Amerada Petroleum Corporation
2.	017970	American Petrofina Co. of Texas
3.*	018260	Anadarko Production Company
4.	032000	The Atlantic Refining Company
5.	057800	Belco Petroleum Corporation
6.	089500	The British-American Oil Producing Co.
7.	108600	Cabot Corporation
8.	112100	California Co. Div. of Calif. Oil Co.
9.	133950	Champlin Oil & Refining Company
10.	140500	Continental Gas Producing Company
11.*	141000	Cities Service Oil Company
12.	141200	Cities Service Production Company
13.	148350	Coastal States Gas Producing Company
14.*	156500	Colorado Oil & Gas Corporation
15.*	158000	Columbian Fuel Corporation
16.	165000	Continental Oil Company
17.	207200	Delhi-Taylor Oil Corporation
18.	219560	Dorchester Gas Producing Company
19.*	237250	El Paso Natural Gas Products Company
20.	273500	Forest Oil Corporation
21.	294500	General American Oil Co. of Texas
22.	329000	Gulf Oil Corporation
23.	404500	J. M. Huber Corporation
24.	407500	Hugoton Plains Gas & Oil Company
25.	408000	Humble Oil & Refining Company
26.	411500	Hassie Hunt Trust
27.	415000	Hunt Oil Company
28.	456500	Kerr-McGee Oil Industries, Inc.
29.*	477000	La Gloria Oil & Gas Company
30.*	507000	Lone Star Producing Company
31.	535900	Magna Oil Corporation
32.	543050	Marathon Oil Company
33.	555000	Mayfair Minerals, Inc.
34.	604500	Murphy Oil Corporation
35.	625500	Northern Natural Gas Producing Co.
36.	626300	Northwest Production Corporation
37.	635750	Odessa Natural Gasoline Company
38.	658450	Pan American Petroleum Corporation
39.	659500	Panhandle Producing Company

* Named as Pipeline Affiliate Respondent in Pipeline Production Proceeding.

[5727]

Line No.	Code Nos. (a)	Company Name (b)
40.	683000	Phillips Petroleum Company
41.	689500	Placid Oil Company
42.*	698500	The Preston Oil Company
43.	709000	The Pure Oil Company
44.	771550	Joseph E. Seagram & Sons, Inc.
45.	776000	The Shamrock Oil & Gas Corporation
46.	781500	Shell Oil Company
47.	786000	Signal Oil & Gas Company
48.	792000	Sinclair Oil & Gas Company
49.	796500	Skelly Oil Company
50.	807200	Socony Mobil Oil Co., Inc.
51.	807500	Sohio Petroleum Company
52.	813590	Southern Natural Gas Company Joint Venture
53.	817000	Southwest Gas Producing Company, Inc.
54.	823100	Standard Oil Company of Texas, Division of California Oil Co.
55.	846500	Sun Oil Company
56.	846650	Sunray DX Oil Company
57.	848000	The Superior Oil Company
58.	854500	Tascosa Gas Company
59.*	860900	Tenneco Oil Company
60.	863150	Texaco, Inc.
61.*	865500	Texas Gas Exploration Corp.
62.	866500	Texas Gulf Producing Company
63.	868700	Texoma Production Company
64.	875500	Tidewater Oil Company
65.	895000	Union Oil Company of California
66.*	895700	Union Producing Company
67.	896070	Union Texas Petroleum, Division of Allied Chemical Corp.
68.	896500	United Carbon Company and Subsidiaries
69.	928500	Western Natural Gas Company

* Named as Pipeline Affiliate Respondent in Pipeline Production Proceeding.

Exhibit 6

[5738]

[5740]

Table No. 1

EXPLORATORY DRILLING
CONTINENTAL U.S. (AREA 99)
1959 to 1965
RESPONDENT GROUPS 1, 3 AND 4, AND TOTAL U.S. PRODUCERS

Line No.	Year (a)	Number of Exploratory Wells 1/ Group 1 Respondents: Drilled: Oil (b)	Gas (c)	Dry (d)	Total (e)	Productive: Total (f)	Percent (f)/(e) (g)	Number of Exploratory Wells 1/ Group 3 Respondents: Drilled: Oil (h)	Gas (i)	Dry (j)	Total (k)	Productive: Total (l)	Percent (l)/(k) (m)
1.	1959	4	29	61	94	33	35.1	12	14	68	94	26	27.7
2.	1960	5	26	87	118	31	26.3	7	14	43	64	21	32.8
3.	1961	2	32	108	142	34	23.9	4	16	42	62	20	32.3
4.	1962	5	26	83	114	31	27.2	5	12	59	76	17	22.4
5.	1963	2	25	49	76	27	35.5	17	16	77	110	33	30.0
6.	1964	3	33	71	107	36	33.6	13	22	92	127	35	27.6
7.	1965	3	29	59	91	32	35.2	21	16	103	140	37	26.4
8.	Total	24	200	518	742	224	30.2	79	110	484	673	189	28.1

Line No.	Year (a)	Number of Exploratory Wells 1/ Group 4 Respondents: Drilled: Oil (b)	Gas (c)	Dry (d)	Total (e)	Productive: Total (f)	Percent (f)/(e) (g)	Number of Exploratory Wells Total United States Producers 2/: Drilled: Oil (h)	Gas (i)	Dry (j)	Total (k)	Productive: Total (l)	Percent (l)/(k) (m)
9.	1959	16	9	42	67	25	37.3	1,702	912	10,577	13,191	2,614	19.8
10.	1960	9	11	70	90	20	22.2	1,321	868	9,515	11,704	2,189	18.7
11.	1961	15	14	85	114	29	25.4	1,157	813	9,022	10,992	1,970	17.9
12.	1962	24	11	95	130	35	26.9	1,211	771	8,815	10,797	1,982	18.4
13.	1963	15	13	98	126	28	22.2	1,314	664	8,686	10,664	1,978	18.5
14.	1964	12	18	62	92	30	32.6	1,219	577	8,951	10,747	1,796	16.7
15.	1965	11	15	125	151	26	17.2	946	515	8,005	9,466	1,461	15.4
16.	Total	102	91	577	770	193	25.1	8,870	5,120	63,571	77,561	13,990	18.0

1/ From PPQ Schedule 23
2/ From Bulletin of American Assoc. of Petroleum Geologists

Table No. 4

PRODUCING AND NON-PRODUCING COMPANY OWNED GAS RESERVES AND
RESERVE TO PRODUCTION RATIOS
CONTINENTAL U.S. (AREA 99)
GROUP 4 OFF-SYSTEM PIPELINE AFFILIATES
1946 to 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 psia and 60°F.)

Line Number	Year (a)	Gas Reserves 1/ Producing (b)	Gas Reserves 1/ Non-Producing (c)	Total (d)	Percent of Total Producing (b)/(d) (e)	Annual 1/ Production (f)	Reserve to Production Ratios: Producing Reserves (b)/(f) (g)	Reserve to Production Ratios: Total Reserves (d)/(f) (h)	Reserve to Production Ratios: AGA-API Total U.S. 2/ (i)
1.	1946	1,519		1,519	100.0	97	15.7	15.7	32.5
2.	1947	1,442		1,442	100.0	77	18.7	18.7	29.5
3.	1948	1,391		1,391	100.0	52	27.0	27.0	28.9
4.	1949	221,639		221,639	100.0	1,215	182.5	182.5	28.9
5.	1950	237,230		237,230	100.0	5,804	40.9	40.9	26.9
6.	1951	232,839		232,839	100.0	4,391	53.0	53.0	24.3
7.	1952	258,221		258,221	100.0	8,414	30.7	30.7	23.1
8.	1953	250,996		250,996	100.0	10,974	22.9	22.9	22.9
9.	1954	250,175		250,179	100.0	8,646	28.9	28.9	22.5
10.	1955	517,635		517,635	100.0	26,653	19.4	19.4	22.1
11.	1956	490,124		490,124	100.0	27,562	17.8	17.8	21.8
12.	1957	466,035		466,035	100.0	30,639	15.2	15.2	21.4
13.	1958	518,167	2,348	520,514	99.5	39,061	13.3	13.3	22.1
14.	1959	889,129	4,625	893,754	99.5	41,925	21.2	21.3	21.1
15.	1960	870,885	14,679	885,564	98.3	44,531	19.6	19.9	20.1
16.	1961	849,611	42,425	892,036	95.2	46,238	18.4	19.3	19.8
17.	1962	855,840	41,906	897,746	95.3	49,391	17.3	18.2	19.9
18.	1963	845,470	44,149	889,618	95.0	47,081	18.0	18.9	18.9
19.	1964	823,642	32,516	856,158	96.2	47,780	17.2	17.9	18.2
20.	1965	795,326	44,950	840,275	94.7	44,730	17.8	18.8	17.5

1/ From PPQ Schedule 22
2/ Calculated from Annual AGA, API and CPA reports of Proved Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the U.S. and Canada. Reserves and production for Alaska have been excluded.

[5744]

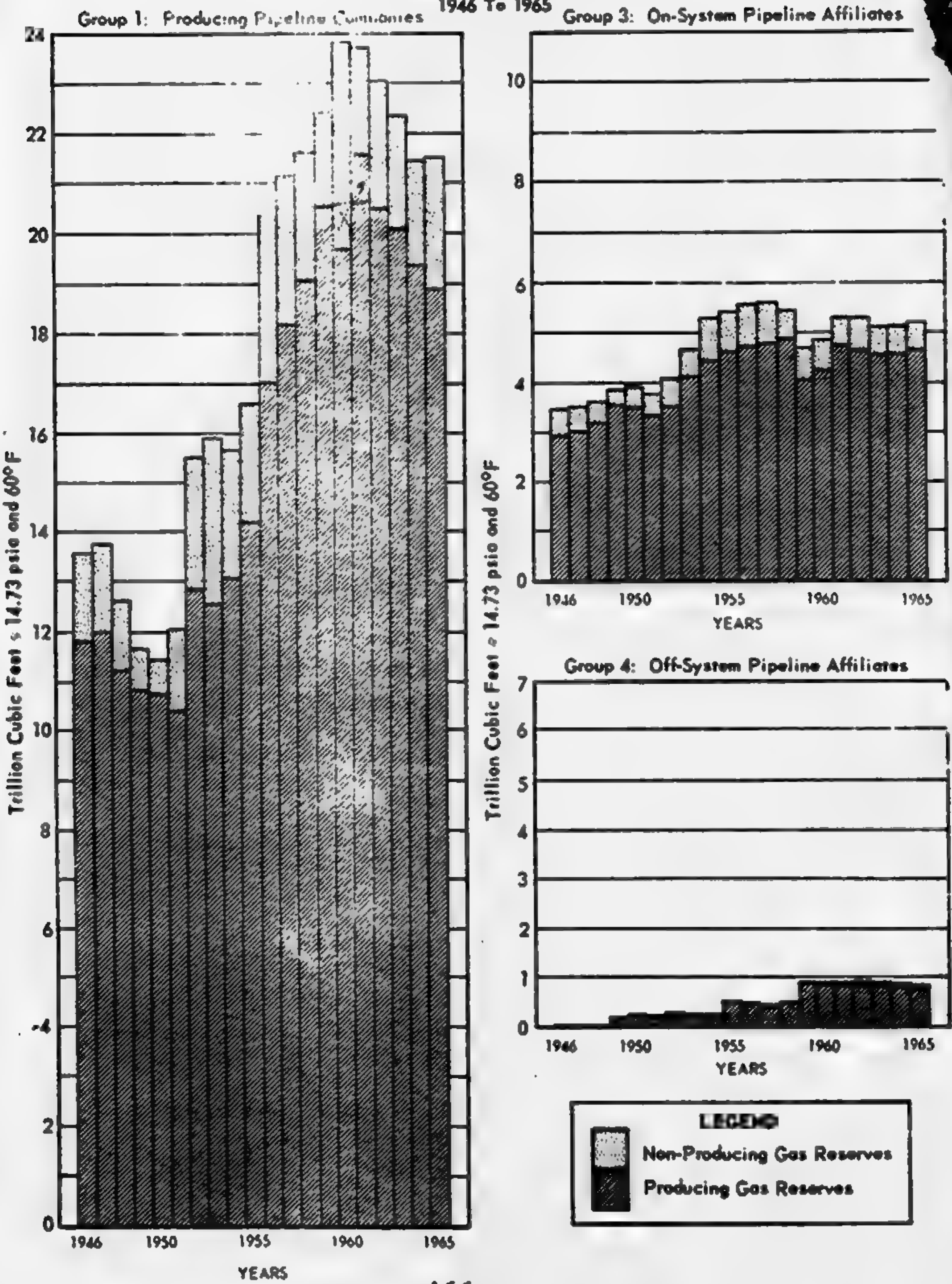
[5744]

[5745]

COMPANY OWNED GAS RESERVES

CONTINENTIAL U.S. (AREA 99)

1946 To 1965



[5747]

COMPARISON OF COMPANY OWNED GAS RESERVES BY RESPONDENT GROUPS 1/
CONTINENTAL U.S. (AREA 99)
1958 to 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 Psia & 60°F.)

Line Number	Year (a)	Total System (b)	On-System (c)	Off-System (d)	Percent On-System (e)
		Group 1 Producing Pipelines			
1.	1958	21,662,588	21,343,556	319,031	98.5
2.	1959	22,464,319	22,113,150	351,169	98.4
3.	1960	24,234,153	23,842,825	391,327	98.4
4.	1961	24,532,755	24,024,499	508,256	97.9
5.	1962	23,516,543	22,933,642	582,901	97.5
6.	1963	22,499,068	21,963,530	535,538	97.6
7.	1964	21,564,234	20,987,657	576,578	97.3
8.	1965	21,921,522	21,377,837	543,686	97.5
		Group 3 On-System Affiliates			
9.	1958	5,485,804	4,146,901	1,338,904	75.6
10.	1959	4,733,671	3,488,202	1,245,469	73.7
11.	1960	4,910,731	3,681,865	1,228,866	75.0
12.	1961	5,306,890	3,900,285	1,406,605	73.5
13.	1962	5,307,638	3,856,760	1,450,877	72.7
14.	1963	5,114,535	3,539,302	1,575,233	69.2
15.	1964	5,128,220	3,504,671	1,623,550	68.3
16.	1965	5,023,564	3,403,400	1,620,164	67.7
		Group 4 Off-System Affiliates			
17.	1958	520,514	514,000	6,515	98.7
18.	1959	893,754	887,525	6,229	99.3
19.	1960	885,564	871,790	13,774	98.4
20.	1961	928,701	873,100	55,601	94.0
21.	1962	897,746	834,376	63,370	92.9
22.	1963	889,619	826,541	63,078	92.9
23.	1964	856,158	802,083	54,075	93.7
24.	1965	840,275	776,148	64,128	92.4

1/ From PFQ Schedule 29

Table No. 13

COMPANY OWNED TOTAL AND PRODUCING GAS RESERVES 1/
RESPONDENT GROUPS 1, 3 AND 4
DECEMBER 31, 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 Psia @ 60°F.)

Line Number	Area (a)	Group 1 - Producing Pipelines: Gas Reserves Total (b)	Group 1: Gas Reserves Producing (c)	Group 1: Percent of Total Reserves Producing (c)/(b) (d)	Group 3 - On-System Affiliates: Gas Reserves Total (e)	Group 3: Gas Reserves Producing (f)	Group 3: Percent of Total Reserves Producing (f)/(e) (g)	Group 4 - Off-System Affiliates: Total (h)	Group 4: Producing (i)	Group 4: Percent of Total Reserves Producing (i)/(h) (j)
1.	01	1,978,040	1,485,782	75.1	3,258	3,258	100.0	4,279	4,279	100.0
2.	02				32,354	32,354	100.0			
3.	03	12,931	10,258	79.3	89,523	85,852	95.9			
4.	04	459,572	459,572	100.0	343,608	334,920	97.5	2,370	2,370	100.0
5.	05	3,941,793	2,180,241	55.3	1,429,285	1,015,729	71.1	64,994	35,593	54.8
6.	06	47,159	47,159	100.0	272,141	269,858	99.2	9,890	9,890	100.0
7.	07	180,795	180,795	100.0	501,334	492,093	98.2	3,820	3,820	100.0
8.	08	39,639	39,639	100.0	241,082	236,489	98.1	5,036	4,287	85.1
9.	09	23,568	23,568	100.0	518,207	457,303	88.2	14,110	14,110	100.0
10.	10	6,608	6,608	100.0	213,519	213,506	99.9			
11.	11				279,827	277,208	99.1			
12.	12				38,142	38,139	99.9	8,000	8,000	100.0
13.	13				113,777	113,777	100.0			
14.	14	4,266,795	4,254,995	99.7	217,270	209,820	96.6	9,943	9,943	100.0
15.	15	274,398	250,696	91.4	27,229	27,227	99.9	10,300	300	2.9
16.	16	647,968	644,470	99.5	251,226	244,805	97.4	11,263	11,263	100.0
17.	17	99,190	99,190	100.0	16,478	16,022	97.2	366	366	100.0
18.	18	4,653	4,653	100.0	68,249	65,909	96.6	149,205	149,205	100.0
19.	19	1,954,363	1,953,862	99.9	557,044	546,484	98.1	533,170	533,170	100.0
20.	20				2,346	2,346	100.0			
21.	21	7,341,359	7,229,959	98.5				8,730	8,730	100.0
22.	22	207,300	10,300	5.0	18,600	17,516	94.1	4,800		0.0
23.	23	5,194	4,047	77.9	743	526	70.8			
24.	24	3,400		0.0	1,816		0.0			
25.	25	2,000		0.0						
26.	88	6,200	6,200	100.0	1,003	1,003	100.0			
27.	99	21,502,926	18,894,682	87.9	5,236,841	4,691,412	89.6	840,275	795,326	94.7

1/ From FPC Schedule 22.

[5758]

[5759]

TOTAL PROVED AND UNPROVED ACREAGE BY AREA 1/ Table No. 14
GROUP 1 PRODUCING PIPELINES
DECEMBER 31, 1965

Line Number	Area (a)	Proved 2/ Acreage (b)	Unproved Acreage (c)	Total Acreage (d)	Percent Proved (e)	Total Acreage Percent of Area 99 (f)
1.	01	2,565,865	3,153,359	5,719,224	44.9	63.5
2.	02		845	845	0.0	0.1
3.	03	2,913	37,359	40,272	7.2	0.4
4.	04	67,407	52,593	120,000	56.2	1.3
5.	05	57,441	100,577	158,018	36.4	1.8
6.	06	15,130	8,483	23,613	64.1	0.3
7.	07	15,374	45,709	61,083	25.2	0.7
8.	08	5,020	28,063	33,083	15.2	0.4
9.	09	1,933	24,188	26,121	7.4	0.3
10.	10	1,208	50,490	51,698	2.3	0.6
11.	11		7,897	7,897	0.0	0.1
12.	12		160	160	0.0	0.1
13.	14	547,796	23,620	571,416	95.9	6.3
14.	15	41,090	107,290	148,380	27.7	1.6
15.	16	151,902	4,562	156,464	97.1	1.7
16.	17	27,309	30,367	57,676	47.3	0.6
17.	18	2,538	184,633	187,171	1.4	2.1
18.	19	310,335	15,987	326,322	95.1	3.6
19.	20		7,524	7,524	0.0	0.1
20.	21	734,800	151,206	886,006	82.9	9.8
21.	22	15,225	230,427	245,652	6.2	2.7
22.	23	3,350	12,137	15,487	21.6	0.2
23.	24	3/	7,988	7,988	0.0	0.1
24.	25	320 4/	2,014	2,334	13.7	0.1
25.	88	2,474	146,865	149,339	16.6	1.7
26.	99	4,569,430	4,434,343	9,003,773	50.8	100.0

1/ From PPQ Schedules 26 and 34.
2/ From Table No. 7, Col. (b).
3/ Respondent combined Areas 23 and 24.
4/ Reported by respondent and included in total but not printed by ADP.

[5761]

TOTAL PROVED AND UNPROVED ACREAGE BY AREA 1/ Table No. 16
GROUP 4 OFF-SYSTEM PIPELINE AFFILIATES
DECEMBER 31, 1965

Line Number	Area (a)	Proved 2/ Acreage (b)	Unproved Acreage (c)	Total Acreage (d)	Percent Proved (e)	Total Acreage Percent of Area 99 (f)
1.	01	5,568	23,944	29,512	18.9	1.3
2.	02		10	10	0.0	0.1
3.	03		41,924	41,924	0.0	1.8
4.	04	1,005	22,237	23,242	4.3	1.0
5.	05	9,418	146,028	155,446	6.1	6.7
6.	06	5,771	77,583	83,354	6.9	3.6
7.	07	870	18,891	19,761	4.4	0.8
8.	08	769	94,733	95,502	0.8	4.1
9.	09	12,139	83,349	95,488	12.7	4.1
10.	10		37,606	37,606	0.0	1.6
11.	11		26,085	26,085	0.0	1.1
12.	12	3,440	6,353	9,793	35.1	0.4
13.	13		18,927	18,927	0.0	0.8
14.	14	2,520	6,473	8,993	28.0	0.4
15.	15	3,536	128,556	132,092	2.7	5.7
16.	16	596	36,332	36,928	1.6	1.6
17.	17	9,333	106,339	115,672	8.1	5.0
18.	18	32	140,658	140,690	0.1	6.0
19.	19	45,175	64,861	110,036	41.1	4.7
20.	20		14,016	14,016	0.0	0.6
21.	21	12,880	80,008	92,888	13.9	4.0
22.	22	1,512	184,995	186,507	0.8	8.0
23.	23		21,187	21,187	0.0	0.9
24.	24		205,000	205,000	0.0	8.8
25.	25		277,761	277,761	0.0	11.9
26.	88		350,635	350,635	0.0	15.1
27.	99	114,564	2,214,490	2,329,054	4.9	100.0

1/ From PPQ Schedules 26 and 34.
2/ From Table No. 9, Col. (b).

[5762]

Table No. 1

ANNUAL GAS RESERVE WITHDRAWAL RATES
CONTINENTAL U. S. (AREA 99)
TOTAL SYSTEM
GROUP 1 PRODUCING PIPELINES
1958 to 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 Psia and 60°F.)

Line Number	Year (a)	Year End 1/ Gas Reserves (b)	Annual 2/ Production (c)	Reserves Plus Production (b)+(c) (d)	Annual Withdrawal Rate (%) (c)/(d) (e)
1.		Company Owned Gas Reserves			
2.	1958	21,662,588	681,480	22,344,068	3.0
3.	1959	22,464,319	752,599	23,216,918	3.2
4.	1960	24,234,153	785,777	25,019,930	3.1
5.	1961	24,532,755	787,220	25,319,975	3.1
6.	1962	23,516,543	754,630	24,271,173	3.1
7.	1963	22,499,068	808,178	23,307,246	3.5
8.	1964	21,564,234	851,555	22,415,789	3.8
9.	1965	21,921,522	898,398	22,819,920	3.9
10.		Reserves Contracted from Pipeline Affiliates			
11.	1958	7,027,252	434,124	7,461,376	5.8
12.	1959	5,892,115	407,532	6,299,647	6.5
13.	1960	5,752,840	379,007	6,131,847	6.2
14.	1961	6,063,813	367,523	6,431,336	5.7
15.	1962	6,579,701	387,939	6,967,640	5.6
16.	1963	4,992,340	379,543	5,371,883	7.1
17.	1964	5,122,390	386,693	5,509,083	7.0
18.	1965	5,325,509	350,056	5,675,565	6.2
19.		Reserves Contracted from Independent Producers			
20.	1958	110,763,762	4,919,892	115,683,654	4.3
21.	1959	109,705,842	5,332,577	115,038,419	4.6
22.	1960	116,687,656	5,796,066	122,483,722	4.7
23.	1961	115,544,470	5,856,457	121,400,927	4.8
24.	1962	115,345,960	6,084,033	121,429,993	5.0
25.	1963	120,783,423	6,452,789	127,236,212	5.1
26.	1964	120,916,525	6,865,693	127,782,218	5.4
27.	1965	120,088,043	7,004,163	127,092,206	5.5

1/ From PPQ Schedule 29
2/ From PPQ Schedule 30

[5763]

ANNUAL GAS RESERVE WITHDRAWAL RATES Table No. 18
CONTINENTAL U. S. (AREA 99)
TOTAL SYSTEM
GROUP 2 NON-PRODUCING PIPELINES
1958 to 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 Psia and 60°F.)

Line Number	Year (a)	Year End 1/ Gas Reserves (b)	Annual 2/ Production (c)	Reserves Plus Production (b)+(c) (d)	Annual Withdrawal Rate (%) (c)/(d) (e)
1.	Reserves Contracted from Pipeline Affiliates				
2.	1958	1,817,845	23,521	1,841,366	1.3
3.	1959	1,781,817	30,886	1,812,703	1.7
4.	1960	1,709,742	44,543	1,754,285	2.5
5.	1961	1,666,458	47,927	1,714,385	2.8
6.	1962	1,481,328	63,412	1,544,740	4.1
7.	1963	1,333,497	64,379	1,397,876	4.6
8.	1964	7,703	638	8,341	7.6
9.	1965	6,960	710	7,670	9.3
10.	Reserves Contracted from Independent Producers				
11.	1958	22,308,484	782,493	23,090,977	3.4
12.	1959	25,275,836	942,382	26,218,218	3.6
13.	1960	25,807,928	1,121,727	26,929,655	4.2
14.	1961	30,899,732	1,452,491	32,352,223	4.5
15.	1962	32,059,829	1,585,876	33,645,705	4.7
16.	1963	32,588,185	1,689,398	34,277,583	4.9
17.	1964	36,091,302	1,860,325	37,951,672	4.9
18.	1965	38,865,832	1,985,896	40,851,728	4.9

1/ From PPQ Schedule 29
2/ From PPQ Schedule 30

[5764]

Table No. 19

ANNUAL GAS RESERVE WITHDRAWAL RATES
CONTINENTAL U. S. (AREA 99)
TOTAL SYSTEM
GROUP 3 AND 4 RESPONDENTS
1958 to 1965

(All Volumes in Millions of Cubic Feet (MMcf) at 14.73 Psia and 60°F.)

Line Number	Year (a)	Year End Gas Reserves 1/ (b)	Annual Production 2/ (c)	Reserves Plus Production (b)+(c) (d)	Annual Withdrawal Rate (%) (c)/(d) (e)
1.		Group 3 On-System Pipeline Affiliates			
2.		Company Owned Gas Reserves			
3.	1958	5,485,804	322,765	5,808,569	5.6
4.	1959	4,733,671	318,723	5,052,394	6.3
5.	1960	4,910,731	311,193	5,221,924	6.0
6.	1961	5,306,890	308,075	5,614,965	5.5
7.	1962	5,307,638	311,238	5,618,876	5.5
8.	1963	5,114,535	328,461	5,442,996	6.0
9.	1964	5,128,220	340,984	5,469,204	6.2
10.	1965	5,023,564	339,035	5,362,599	6.3
11.		Group 4 Off-System Pipeline Affiliates			
12.		Company Owned Gas Reserves			
13.	1958	520,514	39,061	559,575	7.0
14.	1959	893,754	41,925	935,679	4.5
15.	1960	885,564	44,531	930,095	4.8
16.	1961	928,701	46,238	974,939	4.7
17.	1962	897,746	49,391	947,137	5.2
18.	1963	889,619	48,459	938,078	5.2
19.	1964	856,158	47,780	903,938	5.3
20.	1965	840,275	44,730	885,005	5.1

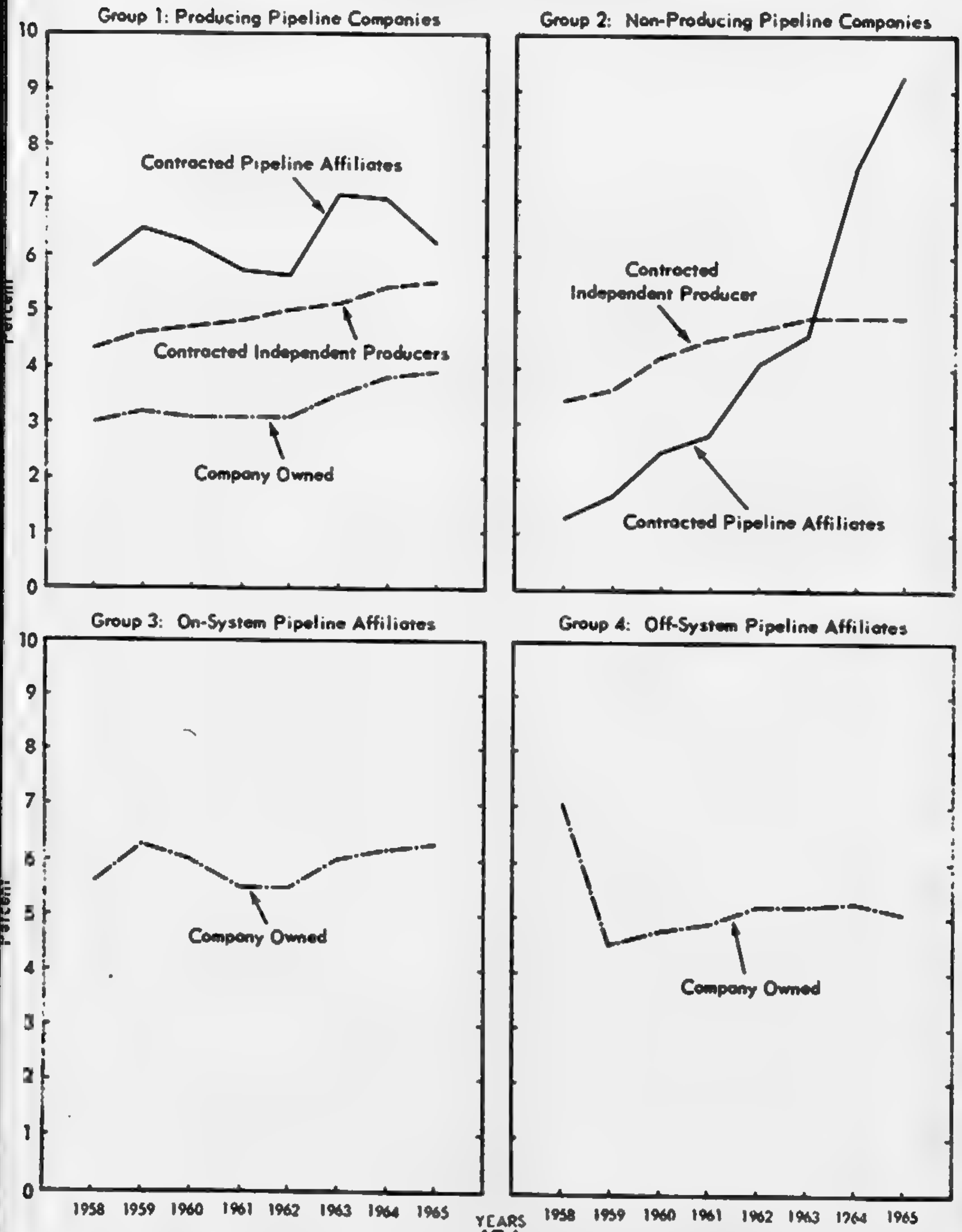
1/ From PPQ Schedule 29
2/ From PPQ Schedule 30

[5765]

[5765]

ANNUAL GAS RESERVES WITHDRAWAL RATES

CONTINENTAL U.S. (AREA 99)
1958 TO 1965



DOCKET NO. RP66-24

PIPELINE PRODUCTION AREA RATE PROCEEDING

SCHEDULE 1

Composite Gross Production, Exploration and Development
Investment (1940-1961) and Owned Gas Reserves (1940-1957)
Group 1 Respondents

Year (1)	Investment and Reserves Both Reported: No. of Cos. (2)	Investment and Reserves Both Reported: Gross Investment (3) (000's omitted)	Investment and Reserves Both Reported: Gas Reserves Mcf (14.73) (4)	Investment Reported (Reserves not Reported): No. of Cos. (5)	Investment Reported (Reserves not Reported): Amount (6) (000's omitted)	Reserves Reported (Investment Not Reported): No. of Cos. (7)	Reserves Reported (Investment Not Reported): Mmcf (14.73) (8)	Totals: No. of Cos. (9)	Totals: Gross Investment (10) (000's omitted)	Totals: Gas Reserves Mmcf (14.73) (11)
1940 1/	[illegible]	$ [illegible]	[illegible]	7	$ 44,310	2	2[illegible],479	17	$105,288	9,90[illegible],[illegible]39
1941 1/	10	70,[illegible]	13,041,[illegible]	7	37,924 4/	3	309,449 4/	18	108,420	13,350,990
1942 1/	17	114,131	[illegible],322	2	1,884 5/	2	238,967 5/	18	116,019	13,71[illegible],289
1943	14	91,944	14,[illegible],433	4	28,729 5/	2	250,154 5/	18	120,673	15,202,597
1944	1[illegible]	151,[illegible]	15,3[illegible],176	0	-	[illegible]	-	18	151,572	15,356,176
1945	1[illegible]	157,[illegible]	15,1[illegible],512	0	-	[illegible]	-	18	157,367	15,159,512
1946	1[illegible]	172,[illegible]	15,[illegible]	0	-	1	192,077	19	172,963	15,773,930
1947	19	202,[illegible]	16,706,481	0	-	0	-	19	202,694	16,706,481
1948	19	204,[illegible]	15,397,607	0	-	0	-	19	204,454	15,397,607
1949	19	206,439	13,289,417	0	-	0	-	19	206,439	13,289,417
1950	19	212,794	13,014,355	0	-	[illegible]	-	19	212,794	13,014,355
1951	19	238,183	13,672,341	0	-	0	-	19	238,183	13,672,341
1952	18	258,450	15,539,479	1	10	0	-	19	258,460	15,539,479
1953	18	286,888	15,908,120	1	4	0	-	19	286,892	15,908,120
1954	18	315,166	15,545,287	1	36	0	-	19	315,204	15,545,287
1955	19	343,456 2/	16,431,806	0	-	1	457	20	343,456 2/	16,432,263
1956	19	391,905 2/	20,191,171	0	-	1	418	20	391,905 2/	20,191,589
1957	19	444,539 2/	21,086,482	1	69	1	385	21	444,608 2/	21,086,867
1958	20	512,492 2/	3/					20	512,492 2/	3/
1959	20	701,193 2/	3/					20	701,193 2/	3/
1960	21	768,877 2/	3/					21	768,877 2/	3/
1961	21	992,233 2/	3/					21	992,233 2/	3/

1/ Although Lone Star Gas Company reported a transfer in 1943 to an affiliate of 857,205,442 Mcf of gas reserves having a book value of $1,077,719, it did not report any production investment for 1940, 1941 or 1942.

2/ For the years 1955-1961, the amounts shown for gross investment include only production investment. The exploration and development investment for such years was not included in the Municipal Gas Group data request since these were covered in Staff Questionaire, FPC Form 50.

3/ Gas reserves for the years 1958-1961, inclusive, were covered in Staff Questionnaire, FPC Form 50, and therefore were not included in the Municipal Gas Group data request.

4/ Includes data for two respondents which reported gas reserves and exploration and development investment but did not report any production investment.

[5809]

Exhibit 21

[5809]

[5819] APPENDIX A

DOCKET NO. RP66-24

PIPELINE PRODUCTION AREA RATE PROCEEDING

Lists of Group 1 and Group 3 Respondents

Group 1

Alabama Tennessee Natural Gas Company
Atlantic Seaboard Corporation
Cities Service Gas Company
Colorado Interstate Gas Company
Cumberland and Allegheny Gas Company
El Paso Natural Gas Company
Hope Natural Gas Company
Humble Gas Transmission Company
Iroquois Gas Company
Kansas-Nebraska Natural Gas Company, Inc.
Kentucky Gas Transmission Corporation
Kentucky-West Virginia Gas Company
Lone Star Gas Company
The Manufacturers Light and Heat Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
New York State Natural Gas Company
Northern Natural Gas Company*
The Ohio Fuel Gas Company
Panhandle Eastern Pipeline Company
Pennsylvania Gas Company
Southern Natural Gas Company
Tennessee Gas Pipeline Company
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Trunkline Gas Company
United Fuel Gas Company
United Gas Pipe Line Company
United Natural Gas Company

Group 3

Anadarko Production Company
Colorado Oil and Gas Company
Lone Star Gathering Company
Lone Star Producing Company
The Preston Oil Company
Texas Gas Exploration Corporation
Union Producing Company

* Reclassified from Group 2 to Group 1 for purposes of the historical analysis summarized in this exhibit.

[5824]

Docket No. RP66-24

Exhibit 23 (WPA-2)

Witness: W. P. Anderson

PIPELINE PRODUCTION GROUP

SUCCESS RATIOS FOR EXPLORATORY WELLS

[5825]

PIPELINE PRODUCTION GROUP

EXPLORATORY WELL DRILLING
PERCENTAGE SUCCESSFUL

Line No.	Year	PIPELINE PRODUCERS Number of Net Wells Drilled	PIPELINE PRODUCERS Percentage Successful	AFFILIATED PRODUCERS Number of Net Wells Drilled	AFFILIATED PRODUCERS Percentage Successful	INDEPENDENT PRODUCERS Number of Net Wells Drilled	INDEPENDENT PRODUCERS Percentage Successful
1	1955	51.4	41.4%	74.9	32.3%	1 968.1	26.5%
2	1956	49.1	39.7	97.8	32.2	2 100.5	29.9
3	1957	48.2	36.3	121.2	28.3	2 016.0	29.8
4	1958	51.8	28.3	86.8	35.0	1 559.5	29.7
5	1959	27.9	43.9	111.4	29.2	1 800.9	31.1
6	1960	54.1	18.0	91.9	27.4	1 583.7	30.2
7	1961	48.6	15.0	114.3	31.1	1 687.9	29.9
8	1962	36.6	39.2	135.4	30.6	1 688.4	29.3
9	Total	367.7	31.7%	833.7	30.6%	14 405.0	29.5%

[5826]

#24

Docket No. RP66-24

Exhibit 24 (WPA-3) 11-1

Witness: W. P. Anderson

PIPELINE PRODUCTION GROUP

SUCCESS RATIOS FOR DEVELOPMENTAL WELLS

[5827]

PIPELINE PRODUCTION GROUP

DEVELOPMENTAL WELL DRILLING
PERCENTAGE SUCCESSFUL

		PIPELINE PRODUCERS		AFFILIATED PRODUCERS		INDEPENDENT PRODUCERS	
Line No.	Year	Number of Net Wells Drilled	Percentage Successful	Number of Net Wells Drilled	Percentage Successful	Number of Net Wells Drilled	Percentage Successful
1	1955	206.2	85.1%	516.7	86.7%	9 276.3	88.2%
2	1956	287.7	88.3	513.9	86.6	10 078.8	88.2
3	1957	293.8	87.8	481.0	87.3	9 491.4	88.0
4	1958	296.1	87.4	278.1	87.5	7 618.2	87.6
5	1959	239.6	83.9	403.5	80.9	8 343.4	87.5
6	1960	234.8	81.2	330.9	85.0	7 641.1	87.0
7	1961	254.9	79.8	428.6	84.9	7 897.1	86.9
8	1962	229.8	80.8	520.3	84.3	7 633.4	85.8
9	Total	2 042.9	84.5%	3 472.4	85.4%	67 979.7	87.5%

[5870]

INDEX

Exhibit 28

Unit Costs of
Exploration and Development
and Transmission
(1955 - 1962)

Curves -

Arkansas Louisiana Gas Company
El Paso Natural Gas Company
Humble Gas Transmission Company
Mississippi River Fuel Corporation
Mountain Fuel Supply Company
New York State Natural Gas Company
Panhandle Eastern Pipe Line Company
Southern Natural Gas Company
Tennessee Gas Transmission Company
Texas Eastern Transmission Corporation
United Fuel Gas Company

Colorado Interstate Gas Company
Kansas-Nebraska Natural Gas Company
Natural Gas Pipeline Company of America

Schedule 1 -

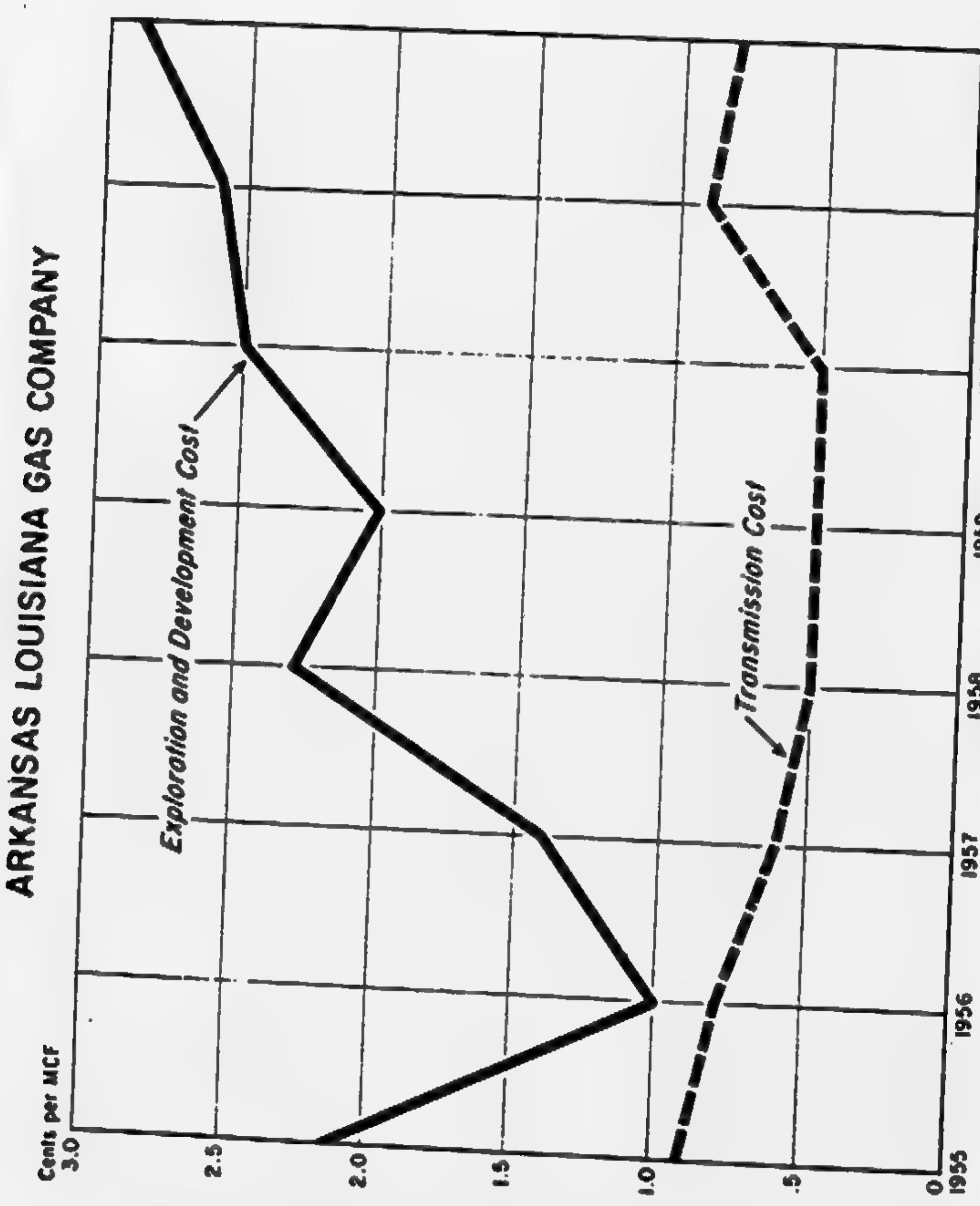
Exploration and Development Costs per Mcf of Gas Produced

Schedule 2 -

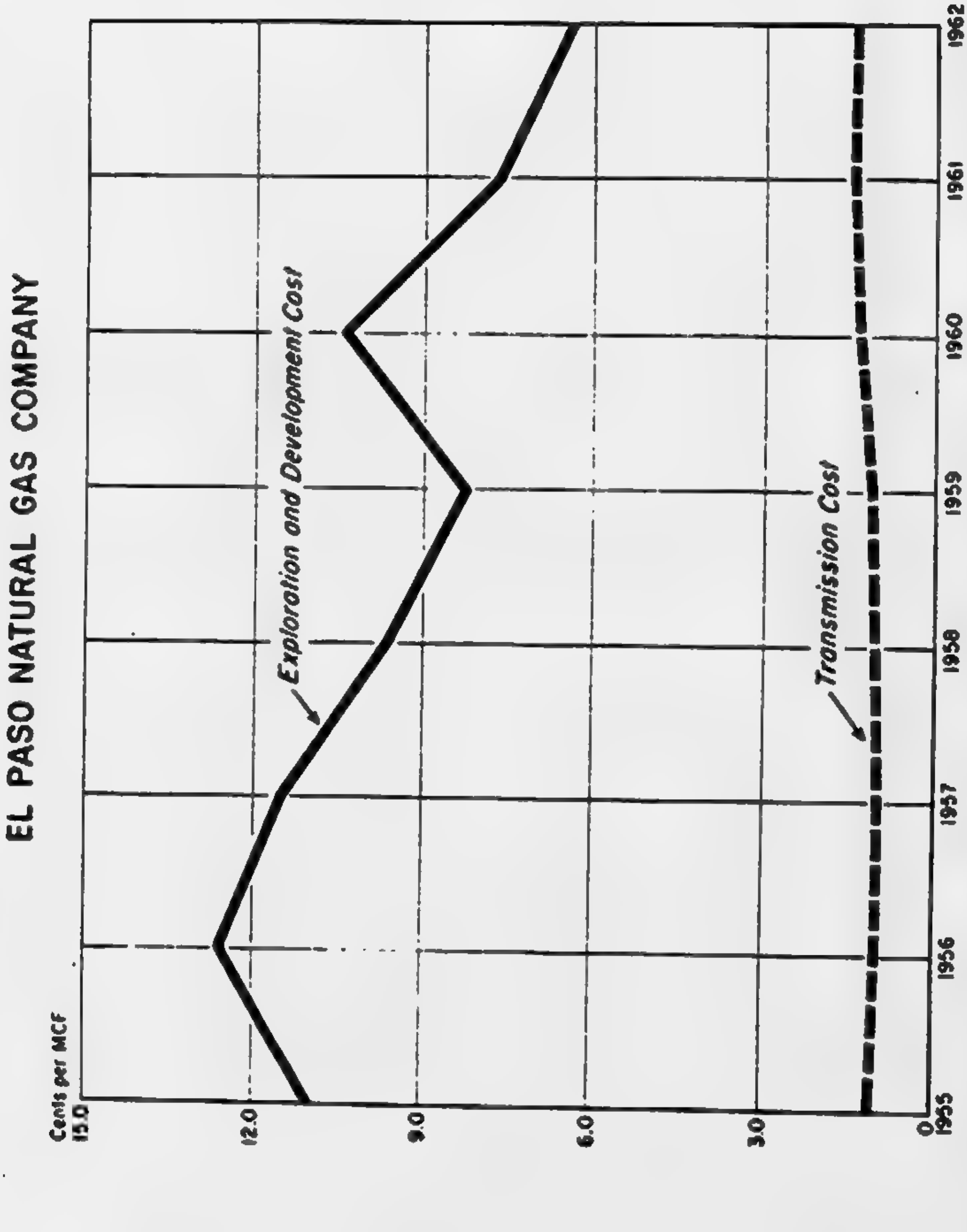
Transmission Costs per Mcf of Gas Delivered

[5871]

[5871]

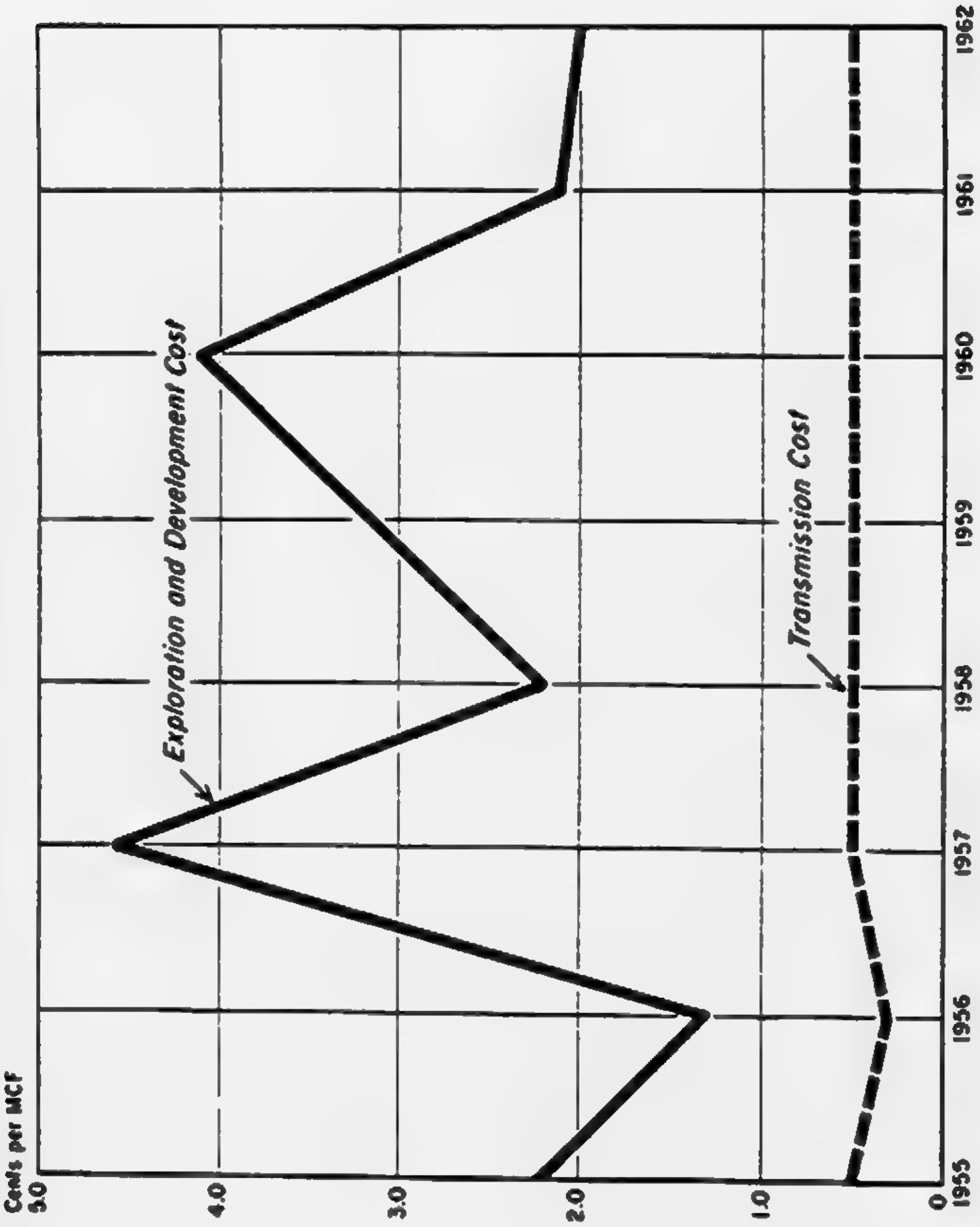

ARKANSAS LOUISIANA GAS COMPANY
Cents per MCF
3.0
2.5
2.0
1.5
1.0
.5
0
1955
1956
1957
1958
1959
1960
1961
1962
Exploration and Development Cost
Transmission Cost

[5872]

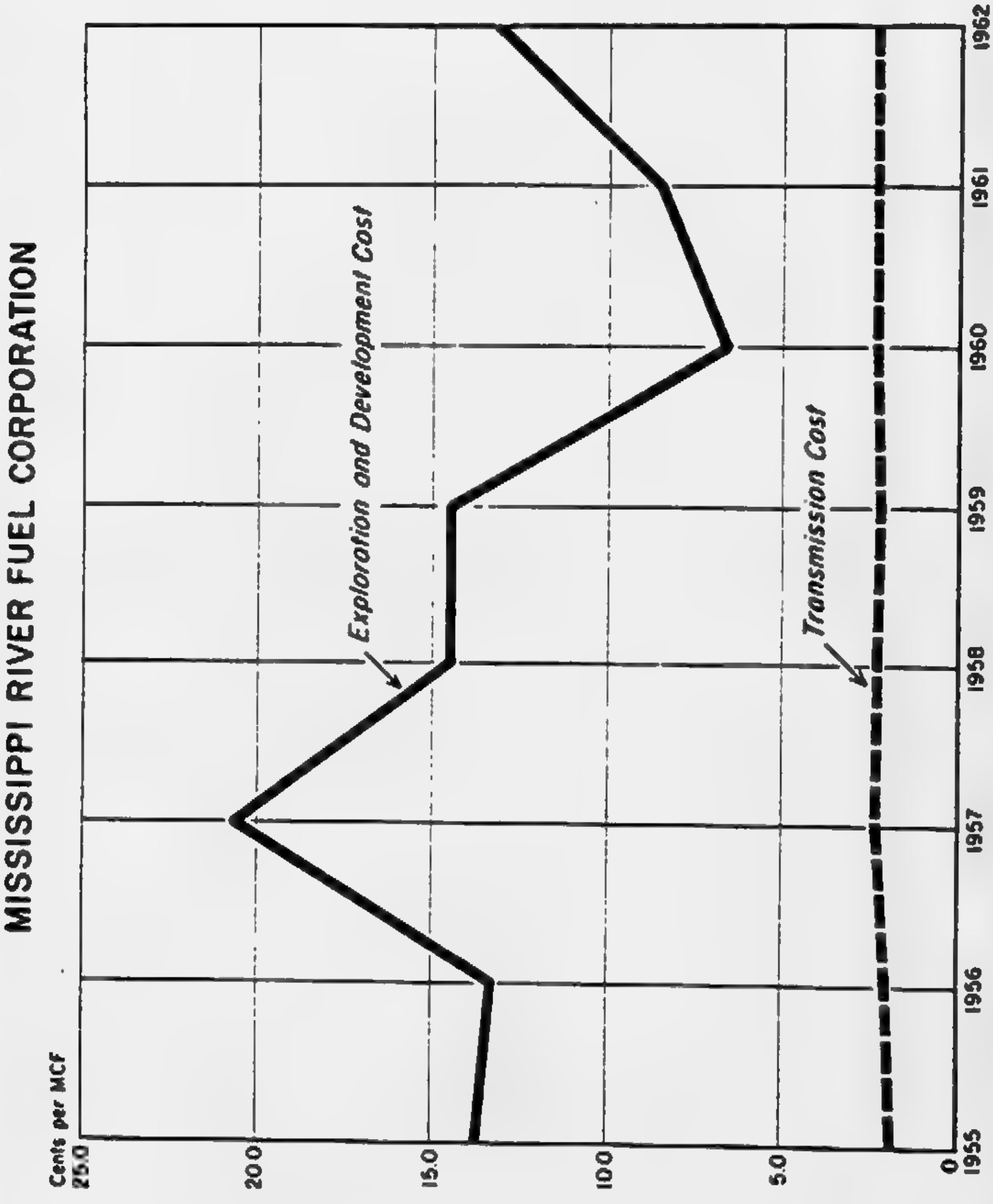

EL PASO NATURAL GAS COMPANY
Cents per MCF
15.0
12.0
9.0
6.0
3.0
0
1955
1956
1957
1958
1959
1960
1961
1962
Exploration and Development Cost
Transmission Cost

[5873]

HUMBLE GAS TRANSMISSION COMPANY

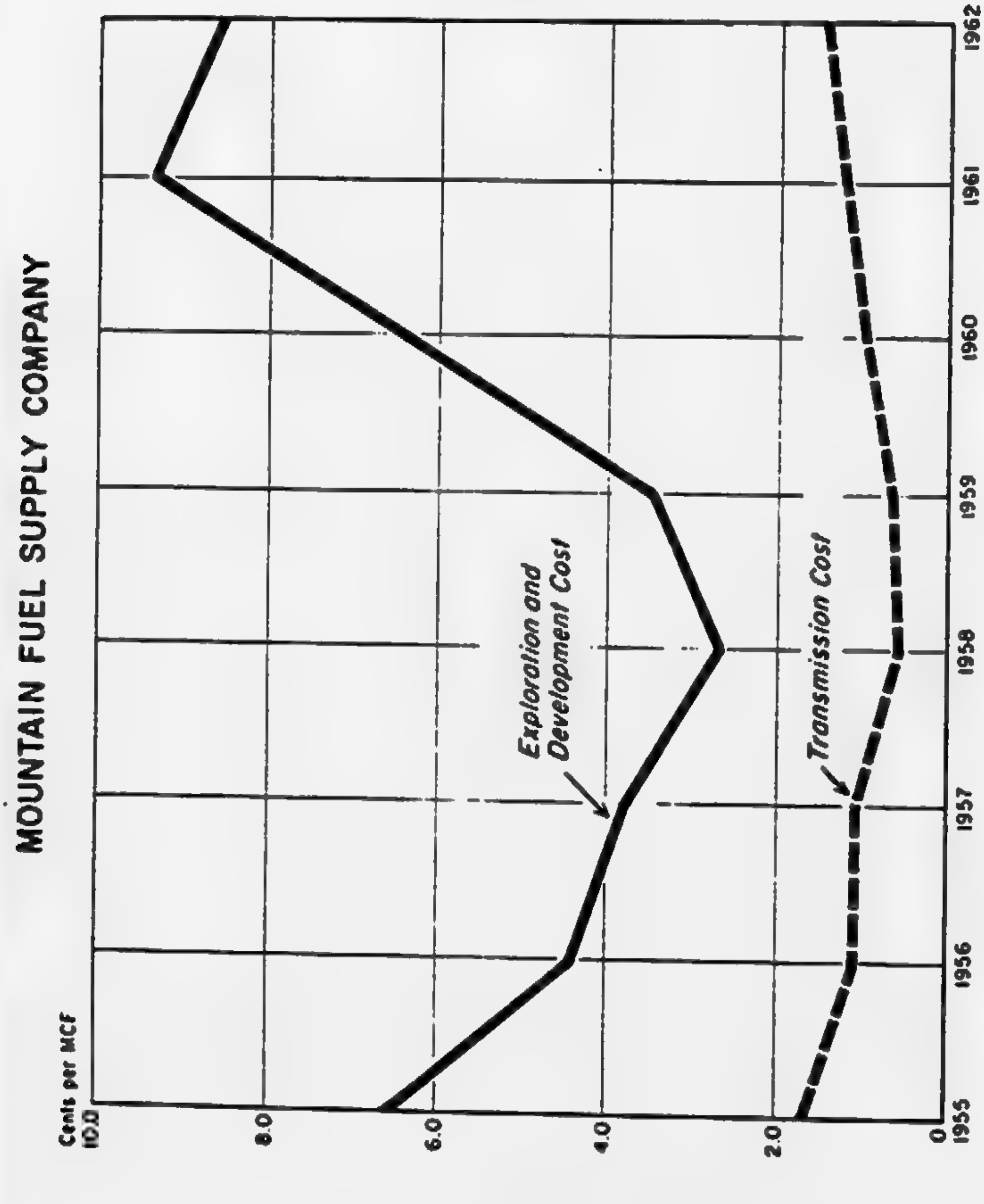


[5874]


MISSISSIPPI RIVER FUEL CORPORATION
Cents per MCF
25.0
20.0
15.0
10.0
5.0
0
1955
1956
1957
1958
1959
1960
1961
1962
Exploration and Development Cost
Transmission Cost

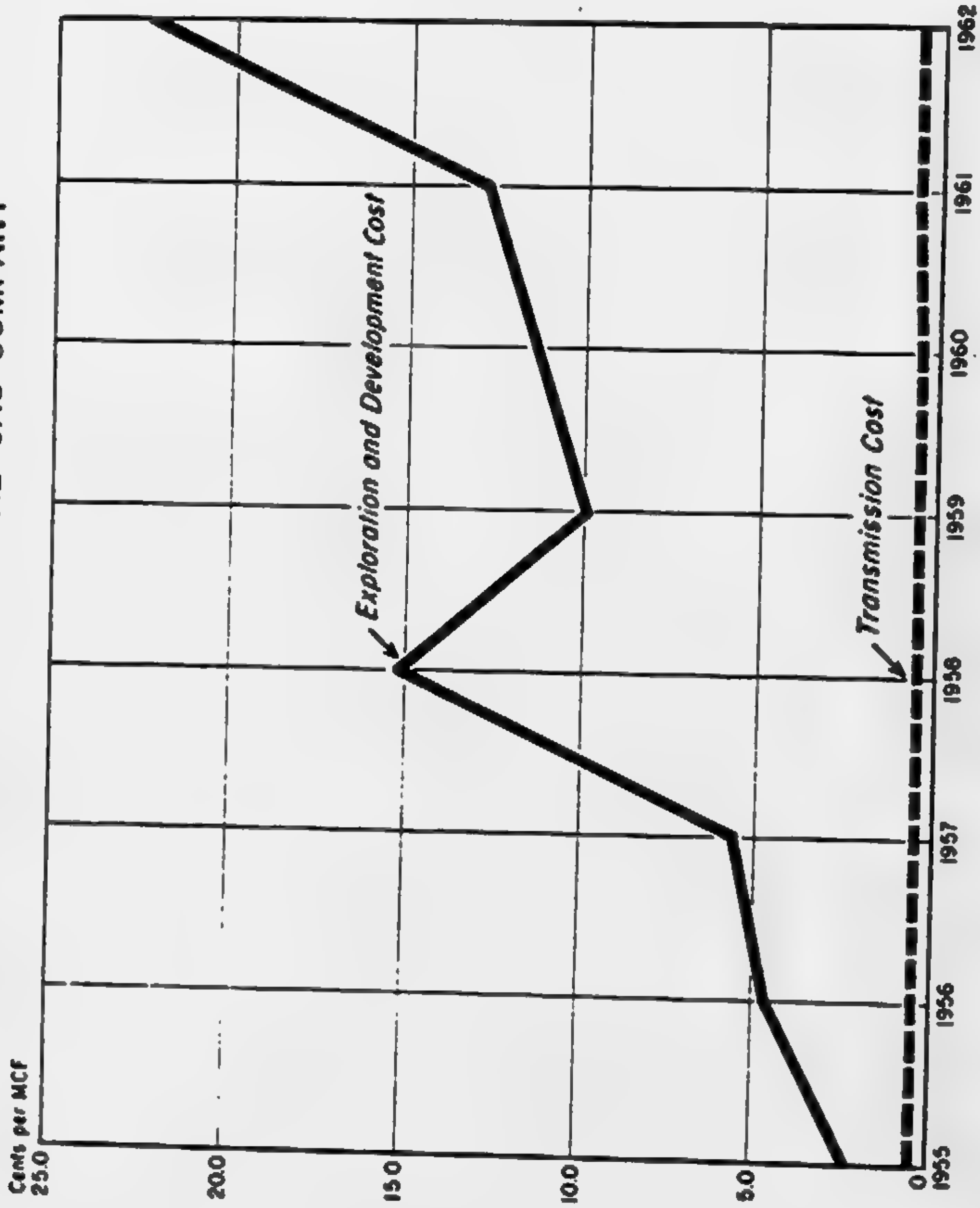
[5875]

[5875]

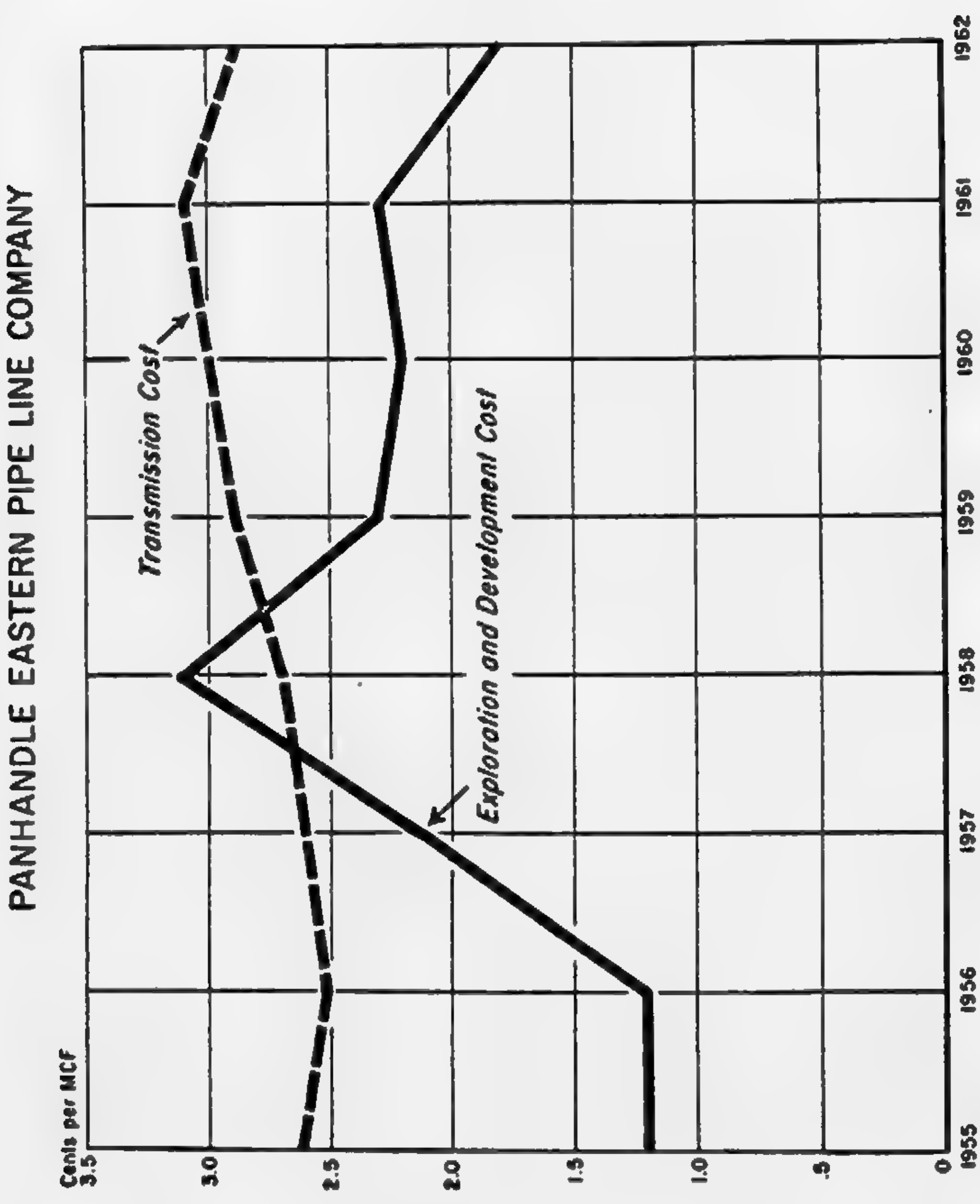

MOUNTAIN FUEL SUPPLY COMPANY
Cents per MCF
10.0
8.0
6.0
4.0
2.0
0
1955
1956
1957
1958
1959
1960
1961
1962
Exploration and Development Cost
Transmission Cost

[5876]

NEW YORK STATE NATURAL GAS COMPANY

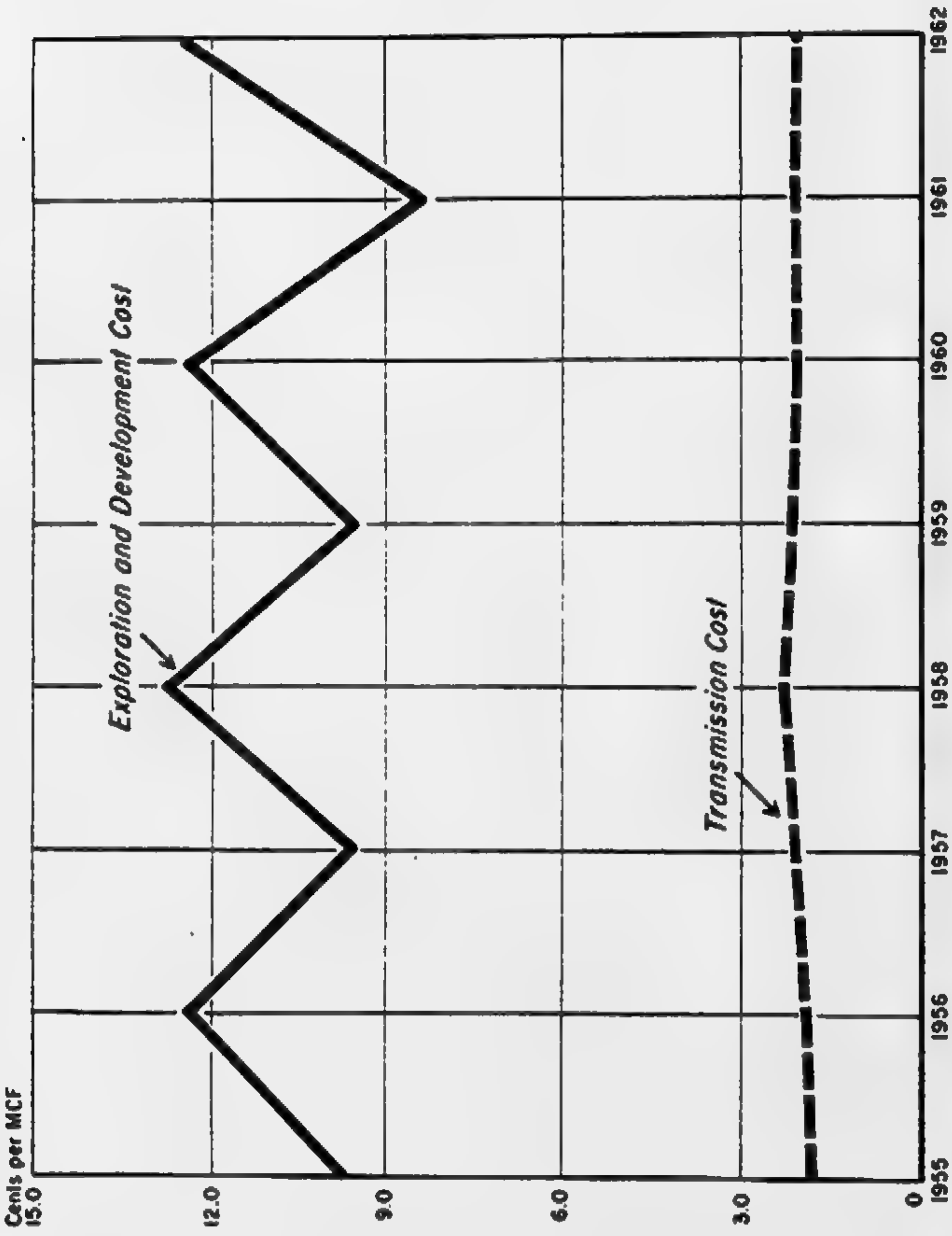


[5877]


PANHANDLE EASTERN PIPE LINE COMPANY
Cents per MCF
3.5
3.0
2.5
2.0
1.5
1.0
.5
0
1955
1956
1957
1958
1959
1960
1961
1962
Transmission Cost
Exploration and Development Cost

[5878]

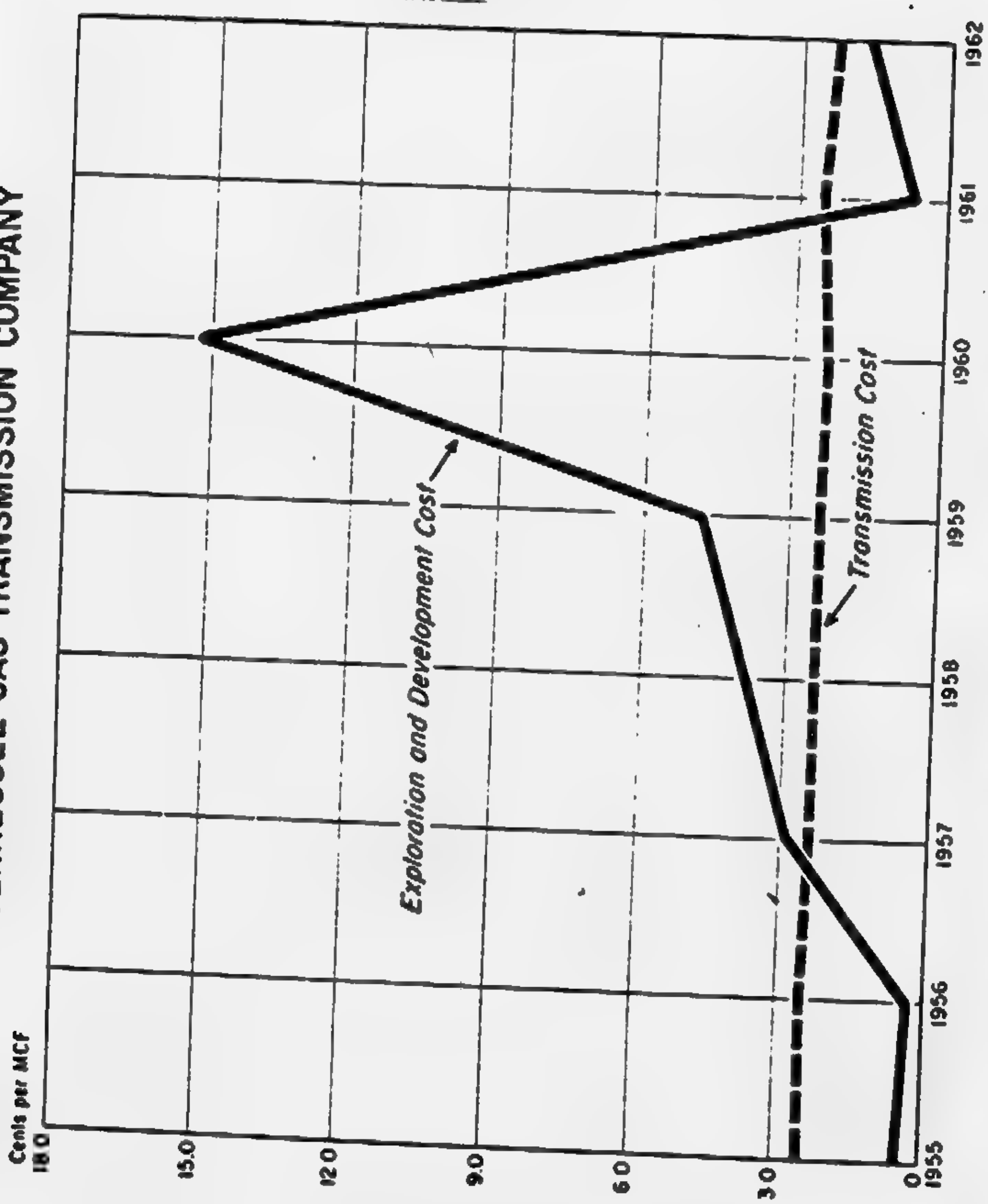
SOUTHERN NATURAL GAS COMPANY



[5879]

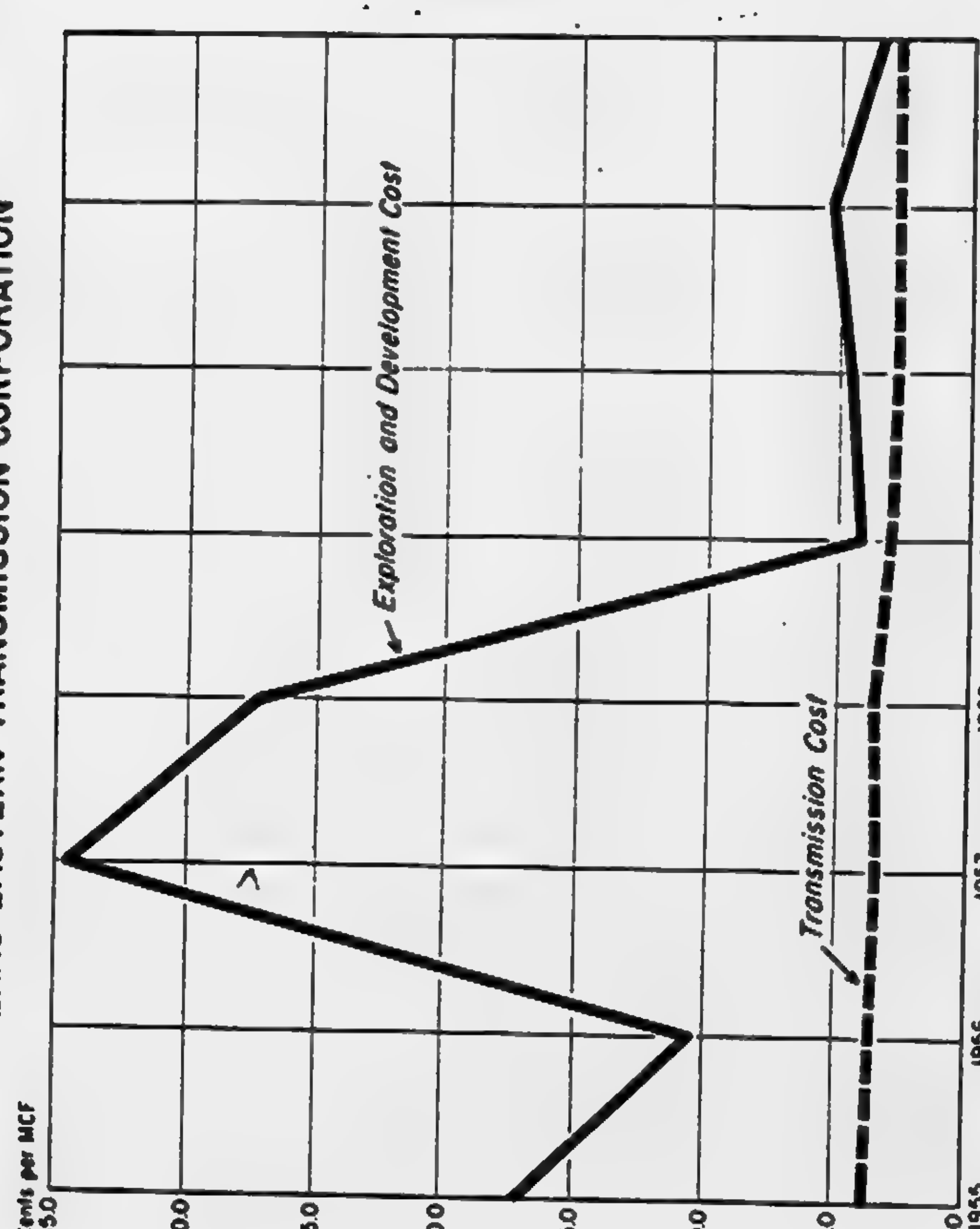
[5879]

TENNESSEE GAS TRANSMISSION COMPANY



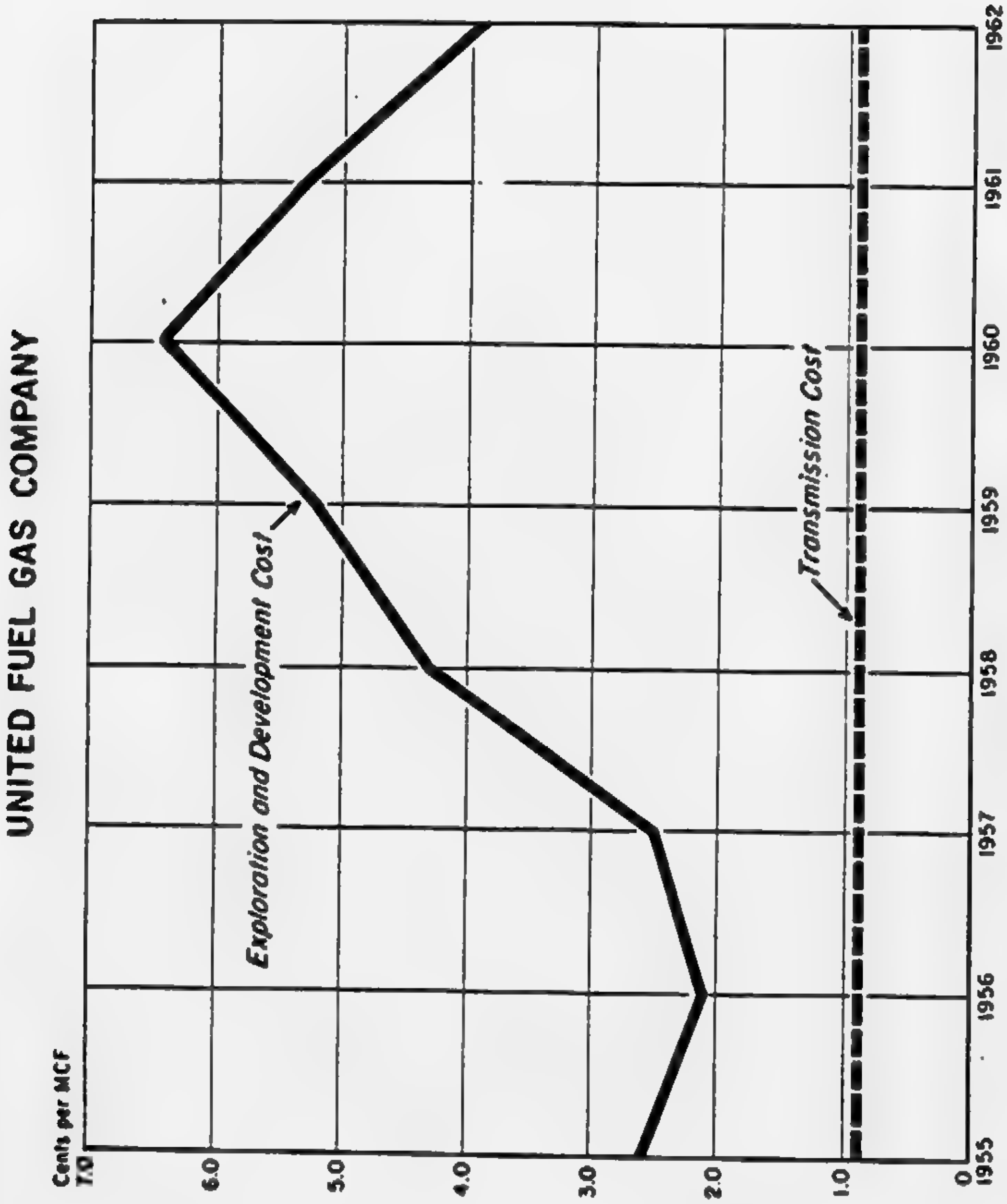
[5880]

TEXAS EASTERN TRANSMISSION CORPORATION



[5881]

[5881]


UNITED FUEL GAS COMPANY
Cents per MCF
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0
1955
1956
1957
1958
1959
1960
1961
1962
Exploration and Development Cost
Transmission Cost

[5887]

#30

Docket No. RP66-24

Exhibit ________(WPA-9)

Witness: W. P. Anderson

PIPELINE PRODUCTION GROUP

DECLINE IN OWNED RESERVES
OF PIPELINE PRODUCERS
1958-1966

5587

[5888]

PIPELINE PRODUCTION GROUP

DECLINE IN OWNED RESERVES OF PIPELINE PRODUCERS
1958 - 1966
14.65 p.s.i.a.

	1958	1966	Change in Reserves MMCF	Change in Reserves Percentage
El Paso Natural Gas Company	13 347 342	8 050 725	(5 296 617)	(39.7)
Colorado Interstate Gas Company	3 268 630	2 227 669	(1 040 961)	(31.8)
Panhandle Eastern Pipe Line Company	3 043 115	1 929 161	(1 113 954)	(36.6)
Natural Gas Pipeline Co. of America	1 424 938	858 885	(566 053)	(39.7)
United Fuel Gas Company	1 359 793	510 351	(849 442)	(62.5)
Kansas-Nebraska Natural Gas Company	1 009 239	914 364	(94 875)	(9.4)
Southern Natural Gas Company	837 223	697 839	(139 384)	(16.6)
Mountain Fuel Supply Company	689 339	640 495	(48 844)	(7.1)
Arkansas-Louisiana Gas Company	652 359	776 000	123 641	19.0
Tennessee Gas Transmission Company	453 719	1 277 428	823 709	181.5
Consolidated Gas Supply Corporation	340 657	707 973	367 316	107.8
Mississippi River Transmission Company	290 110	37 501	(252 609)	(87.2)
Texas Eastern Transmission Corporation	127 737	177 575	49 838	39.0
			[illegible]	(29.9)

[5889]

#31

Docket No. RP66-24

Exhibit 31 (WPA-10)

Witness: W. P. Anderson

PIPELINE PRODUCTION GROUP

RATIO OF RESERVES OWNED BY PIPELINE PRODUCERS
TO TOTAL COMMITTED RESERVES
1958 - 1966

[5890]

PIPELINE PRODUCTION GROUP

RATIO OF RESERVES OWNED BY PIPELINE PRODUCERS
TO TOTAL COMMITTED RESERVES
1958 - 1966

Year	Total Reserves MMcf	Owned Reserves* MMcf	Ratio
1958	106 346 334	26 844 201	25%
1959	107 075 871	26 816 065	25%
1960	123 448 616	24 108 793	20%
1961	123 213 952	22 376 344	18%
1962	124 015 178	21 845 046	18%
1963	135 560 134	21 135 365	16%
1964	135 806 066	20 262 759	15%
1965	137 426 723	20 011 986	15%
1966	142 115 181	18 805 966	13%

* Excludes reserves from Bastian Bay, Ship Shoals and Rayne Fields.

[5899]

#35

Docket No. RP66-24

Exhibit 5 (JCJ-1)

Witness: J. C. Jones

PIPELINE PRODUCTION GROUP

JOINT INTEREST WELLS AND TOTAL WELLS OF
PIPELINE PRODUCERS AND AFFILIATED PRODUCERS
(Twenty-six Companies)

[5900]

[5900]

Schedule 1

PIPELINE PRODUCTION GROUP

JOINT INTEREST WELLS AS OF DECEMBER 31, 1962
EXCLUSIVE OF APPALACHIAN AREA

Classification	Pipeline Producers	Affiliated Producers	Total
Gas	923	285	1 208
Gas Condensate	1 159	1 052	2 211
Oil	274	2 786	3 060
Other	36	40	76
Total	2 392	4 163	6 555

Schedule 2

PIPELINE PRODUCTION GROUP

GROSS WELLS AS OF DECEMBER 31, 1962
EXCLUSIVE OF APPALACHIAN AREA

Classification	Pipeline Producers	Affiliated Producers	Total
Gas	4 264	965	5 229
Gas Condensate	2 221	1 598	3 819
Oil	368	3 823	4 191
Other	39	76	115
Total	6 892	6 462	13 354

[5901]

[5901]

PIPELINE PRODUCTION GROUP

Schedule 3

[5902]

JOINT INTEREST WELLS AS OF DECEMBER 31, 1962
ALL AREAS

Classification	Pipeline Producers	Affiliated Producers	Total
Gas	1 159	285	1 444
Gas Condensate	1 161	1 052	2 213
Oil	274	2 791	3 065
Other	36	40	76
Total	2 630	4 168	6 798

PIPELINE PRODUCTION GROUP

Schedule 4

GROSS WELLS AS OF DECEMBER 31, 1962
ALL AREAS

Classification	Pipeline Producers	Affiliated Producers	Total
Gas	17 725	965	18 690
Gas Condensate	2 307	1 598	3 905
Oil	395	5 382	5 777
Other	39	76	115
Total	20 466	8 021	28 487

[5903]

[5904]

COMPANIES RESPONDING TO
PIPELINE PRODUCTION GROUP SUPPLEMENTAL QUESTIONNAIRE

PIPELINE PRODUCERS

032100	Atlantic Seaboard Corporation
156300	Colorado Interstate Gas Company
185900	Cumberland & Allegheny Gas Company
237200	El Paso Natural Gas Company
393700	Hope Natural Gas Company
407750	Humble Gas Transmission Company
426800	Iroquois Gas Company
449530	Kansas-Nebraska Gas Company, Inc.
541300	The Manufacturers Light & Heat Company
610870	Natural Gas Pipeline Company of America
616100	New York State Natural Gas Company
635900	The Ohio Fuel Gas Company
658900	Panhandle Eastern Pipe Line Company
672650	Pennsylvania Gas Company
813580	Southern Natural Gas Company
860950	Tennessee Gas Pipe Line Company
864700	Texas Eastern Transmission Corporation
884200	Trunkline Gas Company
897200	United Fuel Gas Company
897450	United Natural Gas Company

AFFILIATED PRODUCERS

018260	Anadarko Production Company
477000	La Gloria Oil and Gas Company
507000	Lone Star Producing Company
698500	The Preston Oil Company
865500	Texas Gas Exploration Corporation
895700	Union Producing Company

[5906]

PIPELINE PRODUCTION GROUP

Current Cost of New Nonassociated Gas for Pipeline Production and Comparison with All Producers Current Cost of New Nonassociated Gas

	Cost per Mcf Pipeline Production
Exploration and Development Costs	
Dry Holes	.78¢
Other Exploratory Costs	1.23
Adjustments for Exploration in Excess of Production	.74
Total Exploration and Development Costs	2.75
Production Operating Expense	2.30
Net Liquid Credit	(1.84)
Regulatory Expense	.14
Depletion, Depreciation and Amortization of Production Investment Costs	
Successful Well Costs	2.62
Lease Acquisition Costs	1.45
Cost of Other Production Facilities	.27
Total Depletion, Depreciation and Amortization	4.34
Return on Production Investment at 12%	5.73
Return on Working Capital at 12%	.46
Subtotal	13.88
Royalty at 14%	2.43
Production Taxes at 7%	1.04
Total	17.35¢

Current Cost of New Nonassociated Gas for All Producers

Permian Basin Opinion No. 468	16.43¢
Associated Gas Distributors Initial Brief in Docket No. AR64-2	16.98¢
FPC Staff Initial Brief in Dockets Nos. AR64-1 and AR64-2	16.46¢

[5907]

[5907]

Docket No. RP66-24

Exhbit No. 37 (JCJ-3)
Revised

Witness: J. C. Jones

PIPELINE PRODUCTION GROUP

Unit Cost Array of Gas Only and Gas Condensate Leases
Year 1962

[5908]

PIPELINE PRODUCTION GROUP

Unit Cost Array of Gas Only and Gas Condensate Leases
Year 1962

Page 1

Line No.	Class and Name of Producer	Producer Code Number (1)	Production Volume Mcf @ 14.65 psia All Wells (2)	Production Volume Mcf @ 14.65 psia Gas Wells (3)	% of Gas Well Volume (4)	Production Costs Cash Expense (5)	Production Costs D D & A (6)	Production Costs Return Allowance (7)	Exploration and Development Costs Expenses (8)	Exploration and Development Costs Ret. Allowance (9)	Unit Production and E & D Costs (10)
1	(P) Tennessee Gas Transmission Company	861100	24 733 652	24 733 652	.442%	2.59¢	11.42¢	76.82¢	2.96¢	15.65¢	111.44¢
2	(I) Texoma Production Company	840700	1 713 122	1 712 075	.031	6.00	6.31	3.42	55.49	6.43	53.73
3	(A) Northwest Production Company	626300	2 865 166	2 865 166	.051	6.41	5.92	39.01	30.08	5.18	42.66
4	(P) El Paso Natural Gas Company	237200	88 562 215	88 562 214	1.582	1.09	4.52	31.31	6.61	2.03	51.19
5	(P) New York State Natural Gas Corp.	616100	8 139 620	8 139 620	.145	[illegible] 6.15	4.12	~~[illegible]~~	34.37	2.26	~~40.62~~
6	(A) Odessa Natural Gasoline Company	635750	1 559 120	576 160	.010	2.39	6.46	22.77	5.76	.20	38.24
7	(A) Preston Oil Company	698500	2 251 225	1 577 947	.028	.67	1.50	10.21	17.70	3.78	33.86
8	(I) Coastal State Gas Production Co.	148350	12 963 209	11 813 292	.211	3.71	1.99	12.15	13.40	1.73	32.98
9	(I) Hassie Hunt Trust	411500	6 569 512	5 308 723	.095	4.52	5.37	14.28	7.70	.57	32.54
10	(P) Hope Natural Gas Company	393700	34 523 807	31 826 194	.569	5.59	6.76	9.82	7.47	2.24	29.98
11	(P) Texas Eastern Transmission Corp.	864700	55 613 832	55 287 559	.988	2.46	13.08	7.41	2.50	.76	26.33
12	(I) Signal Oil and Gas Company	786000	17 850 123	5 134 608	.092	2.29	9.18	8.82	3.48	.56	24.31
13	(P) United Fuel Gas Company	[redacted]	54 303 833	54 303 833	.970	4.06	6.16	9.22	4.30	.39	24.13
14	(A) Cities Service Production Company	141200	36 936 326	15 660 044	.280	3.50	4.55	11.02	3.37	1.37	23.81
15	(A) El Paso Natural Gas Products Co.	237250	6 807 564	2 029 992	.036	2.35	5.64	12.26	2.47	.91	23.63
16	(I) Cabot Corporation	108600	41 093 908	37 128 860	.663	6.82	2.77	5.46	6.85	1.30	23.20
17	(I) Forest Oil Corporation	273500	25 464 084	19 799 638	.354	4.13	5.69	9.07	3.65	.75	23.09
18	(I) Southwest Gas Producing Company	817060	10 680 977	10 556 075	.183	3.20	3.36	4.85	9.43	2.03	23.05
19	(I) British-American Oil Producing Co.	089500	23 796 493	15 698 396	.277	2.03	4.20	8.28	4.56	1.06	22.13
20	(I) Hugoton Plains Gas and Oil Co.	407500	14 172 007	14 172 007	.253	.43	4.71	16.24	-	-	21.38
21	(A) Tenneco Oil Company	840900	56 427 122	37 869 237	.677	1.80	5.59	9.21	3.14	1.06	20.78
22	(P) Mountain Fuel Supply Company	597500	23 942 862	23 467 593	.419	1.40	3.12	5.93	8.42	1.47	20.42
23	(I) The Superior Oil Company	848000	210 865 059	150 850 857	2.695	2.17	2.36	9.23	4.80	1.48	20.22
24	(I) Sinclair Oil and Gas Company	792000	211 879 923	137 542 191	2.458	2.57	4.18	7.96	4.42	.70	19.81
25	(I) Dorchester Gas Producing Company	219560	22 466 943	22 446 943	.401	.72	4.06	14.96	-	.03	19.75
26	(P) Mississippi River Fuel Corporation	576300	25 036 828	24 203 890	.432	2.18	3.30	5.37	4.76	1.67	19.28
27	(I) Magna Oil Corporation	535900	10 097 461	10 072 523	.180	2.88	4.16	6.36	3.89	1.97	19.26
28	(I) California Company	112100	173 520 009	52 842 557	.944	2.03	3.17	9.07	3.88	.46	18.59
29	(P) Southern Natural Gas Company	[redacted]	23 906 559	15 460 450	.276	2.27	2.61	4.22	7.73	1.84	18.67
30	(I) Placid Oil Company	689500	32 977 630	19 986 360	.357	1.50	6.11	7.65	4.11	.80	18.17
31	(I) Belco Petroleum Corporation	057580	47 852 996	27 735 881	.496	3.16	1.96	8.50	3.45	.96	17.99
32	(I) Joseph E. Seagram and Sons, Inc.	771550	35 575 071	7 113 259	.127	1.03	3.79	8.54	3.06	.78	17.98
33	(A) Texas Gas Exploration Corporation	865500	18 022 [redacted]	14 039 958	.251	1.62	2.68	3.42	7.35	2.73	17.80
34	(A) Colorado Oil and Gas Corporation	156500	12 743 [redacted]	11 056 349	.198	1.76	6.37	7.93	2.98	.67	17.51
35	(I) The Pure Oil Company	[redacted]	120 736 566	65 809 536	1.176	6.33	2.10	6.15	3.83	.98	17.39
[illegible]	(I) Shell Oil Company	781500	532 959 633	212 063 026	3.769	3.17	3.34	5.48	4.41	.46	17.36
[illegible]	(I) Skelly Oil Company	796500	119 558 537	71 669 656	1.281	1.55	3.16	7.09	4.24	.82	16.63
[illegible]	(I) Lehi-Taylor Oil Corporation	207200	32 630 462	30 556 679	.546	2.47	3.40	7.26	2.40	.66	[illegible]
[illegible]	(I) American Petrofina Company of Texas	017970	13 152 562	8 195 366	.146	2.49	4.32	6.74	2.25	.63	[illegible]
[illegible]	(I) J. M. Huber Corporation	[redacted]	35 235 463	17 [illegible]	.304	2.23	2.10	5.46	5.69	.94	[illegible]

PIPELINE PRODUCTION GROUP

Unit Cost Array of Gas Only and Gas Condensate Leases
Year 1962

Line No.	Class and Name of Producer	Producer Code Number (1)	Production Volume Mcf @ 14.65 psia All Wells (2)	Gas Wells (3)	% of Gas Well Volume (4)	Production Costs Cash Expense (5)	D D & A (6)	Return Allowance (7)	Exploration and Development Costs Expenses (8)	Return Allowance (9)	Unit Production and E & D Costs (10)
41	(A) Lone Star Producing Company	507000	67 933 223	61 676 249	1.102%	2.61¢	3.26¢	5.08¢	3.91¢	1.13¢	15.99¢
42	(I) Continental Oil Company	165000	175 253 730	93 583 125	1.672	2.32	3.43	5.63	3.68	.66	15.79
43	(A) Southern Natural (Joint Venture)	813590	9 115 772	9 115 772	.163	1.13		10.72	3.05	.46	15.36
44	(I) Humble Oil and Refining Company	408000	1 065 424 006	430 839 501	7.697	2.43	2.73	4.88	4.33	.65	15.02
45	(I) General American Oil Company of Texas	294500	39 368 163	18 131 582	.324	1.52	4.45	7.94	.85	.25	15.01
46	(A) La Gloria Oil and Gas Company	477000	6 074 872	2 167 269	.039	3.62	3.86	5.30	1.77	.40	14.95
47	(I) Sun Oil Company	846500	322 380 218	130 281 986	2.328	2.48	2.71	4.83	3.87	.78	14.67
48	(I) Standard Oil Company of Texas	823100	95 530 862	70 101 276	1.253	1.30	1.69	4.45	5.81	1.24	14.49
49	(I) Socony Mobil Oil Company, Inc.	807200	446 767 116	244 850 750	4.375	2.54	2.21	5.62	2.92	.52	13.81
50	(A) Anadarko Production Company	018260	31 707 568	28 466 300	.509	.68	1.39	4.37	6.00	1.31	13.75
51	(I) Pan American Petroleum Corporation	658450	672 775 466	406 191 535	7.257	2.43	2.22	4.20	4.06	.86	13.75
52	(I) Texas Gulf Producing Company	866500	20 869 184	6 827 411	.122	2.22	2.66	5.72	2.61	.48	13.69
53	(I) Amerada Petroleum Corporation	017000	82 742 825	35 117 707	.627	2.76	2.08	4.10	3.77	.82	13.53
54	(P) Arkansas-Louisiana Gas Company	026100	49 507 951	48 508 743	.867	4.14	1.81	3.80	2.69	.89	13.33
55	(I) Atlantic Refining Company	032000	227 059 715	142 181 566	2.540	3.15	1.89	4.87	2.82	.59	13.32
56	(A) Union Producing Company	895700	179 154 550	173 005 657	3.091	1.87	1.90	4.98	3.16	1.04	12.95
57	(I) Sunray DX Oil Company	846650	173 018 918	87 997 186	1.572	1.88	2.06	4.48	3.96	.57	12.95
58	(I) Murphy Corporation	606500	18 220 380	17 330 709	.310	2.06	2.91	2.39	4.23	.89	12.48
59	(I) Phillips Petroleum Corporation	683000	467 434 442	362 309 837	6.473	2.19	2.76	3.49	3.12	.78	12.34
60	(I) Union Texas Petroleum	896070	75 519 294	72 028 692	1.287	1.20	1.08	3.21	5.68	1.05	12.22
61	(I) Western Natural Gas Company	928500	37 559 852	32 077 233	.573	2.00	2.19	4.60	2.78	.51	12.08
62	(I) United Carbon Company	896500	81 677 000	79 039 000	1.412	3.70	1.85	3.05	2.91	.55	12.06
63	(I) Marathon Oil Company	543050	136 134 848	76 044 079	1.359	3.02	2.33	3.85	2.20	.57	11.97
64	(I) Tidewater Oil Company	[illegible]	[illegible] 750	108 280 593	1.935	2.32	2.60	4.22	2.12	.26	11.52
65	(I) Gulf Oil Corporation	349000	[illegible] 685	218 108 732	3.897	1.58	1.85	4.81	2.68	.46	11.38
66	(I) Kerr-McGee Oil Industries	456500	60 196 342	56 179 867	1.004	2.28	1.20	3.16	3.70	1.00	11.34
67	(I) Hunt Oil Company	433000	37 709 774	31 361 272	.560	1.66	2.01	3.40	3.91	.34	11.32
68	(I) Texaco, Inc.	863150	585 331 161	277 317 163	4.955	1.35	2.34	4.31	2.42	.48	10.90
69	(I) Sohio Petroleum Company	807500	51 929 947	32 977 257	.589	1.48	2.30	3.12	3.50	.45	10.85
70	(I) Union Oil Company of California	895000	184 155 759	159 347 622	2.847	1.17	1.79	3.36	3.43	.95	10.70
71	(A) Pecos Company	670500	1 115	1 115	0.000	9.69	-	.18	-	-	9.87
72	(I) Champlin Oil and Refining Company	133950	82 220 852	70 559 408	1.261	2.27	1.36	2.26	3.24	.39	9.52
73	(A) Cities Service Oil Company	161000	143 583 240	103 123 512	1.843	1.82	.91	3.37	2.83	.52	9.45
74	(I) Northern Natural Gas Producing Co.	625500	56 822 551	56 420 765	1.008	.89	.68	2.00	4.72	.85	9.14
75	(P) Panhandle Eastern Pipe Line Company	658900	76 678 816	76 199 763	1.326	3.37	.68	2.69	1.97	.26	8.97
76	(I) Shamrock Oil and Gas Corporation	776000	86 501 767	72 958 573	1.304	1.25	1.23	3.73	2.15	.42	8.78
77	(P) Kansas-Nebraska Natural Gas Company	449590	28 928 337	28 928 337	.517	1.17	1.82	5.24	.42	.06	8.71
78	(A) Columbian Fuel Corporation	158000	35 082 281	34 594 293	.618	3.28	1.43	2.10	1.09	.20	8.10
79	(P) Humble Gas Transmission Company	407750	31 671 881	31 594 598	.565	1.50	1.94	2.03	2.01	.21	7.69
80	(I) Mayfair Minerals, Inc.	555000	18 407 826	18 363 589	.328	1.77	1.53	1.36	2.32	.11	7.09

Page 2

[5909]

PIPELINE PRODUCTION GROUP

Unit Cost Array of Gas Only and Gas Condensate Leases
Year 1962

Line No.	Class and Name of Producer	Producer Code Number (1)	Production Volume Mcf @ 14.65 psia: All Wells (2)	Production Volume Mcf @ 14.65 psia: Gas Wells (3)	% of Gas Well Volume (4)	Production Costs: Cash Expense (5)	Production Costs: D D & A (6)	Production Costs: Return Allowance (7)	Exploration and Development Costs: Expenses (8)	Exploration and Development Costs: Return Allowance (9)	Unit Production and E & D Costs (10)
81	(A) Cities Service Company	140000	29 189 937	21 679 842	.387%	4.55¢	.05¢	.91¢	.56¢	.01¢	6.08¢
82	(I) Tescoma Gas Company	854500	7 989 480	7 989 480	.143	.91	1.94	2.25	-	-	5.10
83	(P) Colorado Interstate Gas Company	156300	106 065 642	106 065 642	1.895	.86	.57	1.56	.14	.02	3.15
84	(P) Natural Gas Pipeline Company	610870	44 457 044	44 457 044	.794	.28	.46	1.14	.24	.01	2.63
85	(I) Panhandle Producing Company	659500	3 510 328	3 342 176	.060	.83	.79	.88	-	-	2.50
86	(I) Continental Gas Producing Company	140500	44 363 727	44 363 727	.793	.54	.50	.79	-	-	1.83
	Total		9 023 643 437	5 596 748 068	100.000%						

2 25 910 55

[5910]

[5945]

Exhibit No. 54
Schedule No. 9
Sheet 1 of 1

Pipeline Production Area Rate Proceeding

Computed Required Rate of Return on Total Capital
(Less Net Well Mouth Plant Investment) so that Composite Rate of Return
On Total Capital Will Be Equal to 6.5%, Assuming 12% Return on
Net Well Mouth Plant Investment
Year 1960

Line No.	Company (a)	Long Term Debt, Preferred Stock, and Deferred Income Tax 1/ (b)	Common Equity Capital 1/ (c)	Total Capital (b)+(c) (d)	Total Capital x 6.5% (e)	Composite Cost of Long Term Debt And Preferred Stock Capital 1/ (f)	Net Well Mouth Plant Investment 1/ 2/ (g)	Net Well Mouth Plant Investment x 12% (h)	Total Capital Less Net Well-Mouth Plant Investment (d)-(g) (i)	Total Capital x 6.5% Less Net Well Mouth Plant Investment x 12% (e)-(h) (j)	Rate Of Return on Total Capital Less Net Well Mouth Plant Investment (j)÷(i) (k)
1.	Atlantic Seaboard Corporation	55,810,460	47,715,100	103,525,560	6,729,161	2,442,120	393,090	47,171	103,132,470	6,681,990	6.479
2.	Cities Service Gas Company	45,911,499	117,075,127	162,986,626	10,594,144	1,921,734	1,099	204	162,985,127	10,593,960	6.500
3.	Colorado Interstate Gas Company	119,426,500	56,867,667	176,294,167	11,459,121	5,709,320	14,609,145	1,753,100	161,685,022	9,706,021	6.003
4.	Consolidated Gas Supply Corporation	173,925,000	181,324,759	355,249,759	23,091,202	7,500,532	59,454,254	7,044,510	296,795,005	16,076,692	5.417
5.	Cumberland and Allegheny Gas Company	6,991,184	6,559,750	13,450,934	874,311	307,460	2,376,463	285,176	11,074,471	589,135	5.320
6.	El Paso Natural Gas Company	901,073,112	240,619,967	1,151,692,009	75,549,992	44,550,732	200,276,260	24,753,151	955,415,749	50,756,830	5.313
7.	Humble Gas Transmission Company	0	14,909,470	14,909,470	1,089,142	0	4,895,644	824,277	10,024,226	277,865	2.777
8.	Iroquois Gas Corporation	59,000,000	82,[illegible]	141,[illegible]	9,179,192	2,977,975	1,372,990	164,597	140,153,491	9,014,495	6.444
9.	Kansas-Nebraska Natural Gas Company, Inc.	44,213,[illegible]	26,[illegible]	70,534,110	4,578,217	2,077,005	7,448,604	898,432	62,945,506	3,679,585	5.846
10.	Kentucky-West Virginia Gas Company	0	19,395,646	19,395,646	1,[illegible]	0	10,443,099	2,212,972	9,912,595	(370,752)	-
11.	Manufacturers Light and Heat Company	76,994,[illegible]	71,303,910	148,[illegible]	9,[illegible]	3,519,195	3,034,952	364,414	145,264,458	9,274,008	6.385
12.	Mississippi River Transmission Corporation	27,954,000	14,315,536	44,269,536	2,916,220	1,390,700	996,640	119,598	43,262,988	2,757,022	6.375
13.	Natural Gas Pipeline Company of America	352,476,000	181,[illegible]	533,595,989	34,677,233	16,[illegible]	4,531,646	1,023,736	528,964,[illegible]	33,653,507	6.411
14.	The Ohio Fuel Gas Company	88,848,000	86,923,002	175,771,002	11,425,115	6,[illegible]	5,723,570	686,589	170,049,426	10,738,526	6.315
15.	Panhandle Eastern P/L Company	254,019,182	122,309,264	376,318,446	24,465,249	10,131,934	15,588,580	1,906,630	360,499,866	22,558,619	6.258
16.	Pennsylvania Gas Company	14,880,000	24,433,763	39,313,763	2,555,395	728,775	2,910,692	350,003	36,397,072	2,205,392	6.059
17.	Southern Natural Gas Company	108,244,200	129,045,746	237,289,946	15,423,846	4,466,263	16,422,122	1,970,655	220,867,824	13,453,191	6.091
18.	Tennessee Gas Transmission Company	1,350,292,800	498,233,382	1,848,526,182	120,154,202	65,259,234	229,451,796	27,534,216	1,619,074,386	92,619,986	5.721
19.	Texas Eastern Transmission Corporation	750,841,782	211,176,301	962,020,083	62,531,305	30,169,507	33,329,433	3,999,412	928,731,650	58,531,893	6.302
20.	Texas Gas Transmission Corporation	160,934,250	98,673,913	259,608,163	16,874,531	7,607,451	607,452	72,894	259,000,711	16,801,637	6.487
21	Trunkline Gas Company	173,559,960	62,216,159	234,776,119	15,260,447	8,563,700	1,975,496	237,060	232,800,623	15,023,387	6.453
22.	United Fuel Gas Company	89,112,640	98,402,836	187,515,476	12,188,506	4,201,046	44,192,765	5,303,129	143,322,739	6,885,377	4.804
23.	United Natural Gas Company	10,631,000	40,398,029	51,029,029	3,316,887	190,553	4,624,022	555,303	46,405,007	2,761,584	5.976
24.	Total	4,864,181,220	2,466,494,122	7,330,675,342	476,493,999	232,735,954	684,030,319	82,083,687	6,646,645,123	394,410,272	5.934

(a) Deferred Income Taxes are only those resulting from rapid amortization (Acct. No. 281) only. Other deferred income taxes are not included.

1/ Data taken from, "Statistics of Interstate Natural Gas Pipeline Companies - 1960."

2/ Includes Producing Lands, Producing Leaseholds, Gas Rights, Producing Gas Wells - Well Construction, and Producing Gas Wells - Well Equipment.

[6025]

Exhibit No. 58 (WRF-1)
Schedule 13

COMPARISON OF JOINT INTEREST PERCENTAGES BY GROUP INCLUSIVE AND EXCLUSIVE OF APPALACHIAN AREA BASED ON J. C. JONES' EXHIBIT NO. 35 DECEMBER 31, 1962

		Pipeline Producers (1)	Affiliated Producers (2)	Total (3)
Exclusive of Appalachian Area				
(a)	Joint Interest Wells	2,392	4,163	6,555
(b)	Gross Wells	6,892	6,462	13,354
(c)	Joint Interest Percentage	34.7%	64.4%	49.1%
All Areas				
(d)	Joint Interest Wells	2,630	4,168	6,798
(e)	Gross Wells	20,466	8,021	28,487
(f)	Joint Interest Percentage	12.9%	52.0%	23.9%

Source: Lines (a), (b), (d), and (e) are from Pipeline Production Group Witness Jones' Exhibit No. 35, Schedules 1 through 4.

[6029]

Exhibit No. 58 (WRF-1)
Schedule 17

Excluding El Paso Natural Gas Company

GAS RESERVES ADDED PER SUCCESSFUL GAS WELL FOOT DRILLED FOR PIPELINES USED BY J. C. JONES IN EXHIBIT NO. 36
1955 - 1962

	Total Reserves Added (MMcf @ 14.65) (1)	Successful Gas Well Footage Drilled (Feet) (2)	Reserves Added Per Successful Gas Well Foot Drilled (Mcf @ 14.65) (3)
1955	1,310,306	856,197	1,530.4
1956	560,701	1,117,800	501.6
1957	997,756	1,268,977	786.3
1958	451,600	1,208,665	373.6
1959	608,715	1,117,001	545.0
1960	597,298	906,370	659.0
1961	(793,212)	933,408	(849.8)
1962	529,616	846,863	625.4
1955-1962	4,262,780	8,255,281	516.4
1956-1962	2,952,474	7,399,084	399.0
1957-1962	2,391,773	6,281,284	380.8
1958-1962	1,394,017	5,012,307	278.1
1959-1962	942,417	3,803,642	247.8
1960-1962	333,702	2,686,641	124.2
1955-1957	2,868,763	3,242,974	884.6
1955-1958	3,320,363	4,451,639	745.9

Source: Schedule 16 of this exhibit, excluding data for El Paso Natural Gas Company

[6030]

Exhibit No. 58 (WR
Schedule 18

CURRENT COST OF
NEW NONASSOCIATED GAS FOR PIPELINE PRODUCTION
PER J. C. JONES AND COMPARISON WITH "ALL PRODUCER'S
CURRENT COST OF NEW NONASSOCIATED GAS" PER OPINION 468

	Cost Per Mcf Pipeline Production (1)	Opinion 468 (2)	Column (2) As Percent of Column (1) (3)
Exploration and Development Costs			
Dry Holes	.78¢	1.42	182.1%
Other Exploratory Costs	1.23	1.59	129.3
Adjustments for Exploration in Excess of Production	.74	1.11	150.0
Total Exploration and Development Costs	2.75	4.12	149.8
Production Operating Expense	2.30	2.70	117.4
Net Liquid Credit	(1.84)	(3.10)	168.5
Regulatory Expense	.14	.14	100.0
Depletion, Depreciation and Amortization of Production Investment Costs			
Successful Well Costs	2.62	2.88	109.9
Lease Acquisition Costs	1.45	.76	52.4
Cost of Other Production Facilities	.27	.31	114.8
Return on Production Investment at 12%	5.73	5.21	90.9
Return on Working Capital at 12%	.46	.35	76.1
Royalty	2.43 1/	2.05 2/	84.4
Production Taxes at 7%	1.04	1.01	97.1

1/ @ 14.0%
2/ @ 12.5%

Source: Column (1) - Pipeline Production Group Witness Jones' Exhibit No. 36
Column (2) - Opinion 468, 34 FPC 159, 192

[6031]

Exhibit No. 58 (WRF-1)
Schedule 19

QUARTILE PERCENTAGE DISTRIBUTION OF UNIT COST DATA
BASED ON J. C. JONES' EXHIBIT NO.37 (REVISED)

	All Companies (1)	Independent Producers (2)	Affiliates (3)	Pipeline Producers (4)
Number of Instances				
First Quartile	21	9	6	6
Second Quartile	22	15	4	3
Third Quartile	21	17	3	1
Fourth Quartile	22	13	4	5
	86	54	17	15
Percentage Distribution				
First Quartile	24.4%	16.7%	35.3%	40.0%
Second Quartile	25.6	27.8	23.5	20.0
Third Quartile	24.4	31.5	17.7	6.7
Fourth Quartile	25.6	24.0	23.5	33.3
	100.0%	100.0%	100.0%	100.0%
First & Fourth Quartiles	50.0%	40.7%	58.8%	73.3%
Second & Third Quartiles	50.0%	59.3%	41.2%	26.7%

Source: Number of Instances - Transcript page 2669

Percentage Distribution - Based on number of instances

[6032]

Exhibit No. 58 (WRF-1)
Schedule 20
Page 1 of 4

COMPUTATION OF WEIGHTED AVERAGE COSTS
BY GROUP FOR ALL COMPANIES SHOWN ON
J. C. JONES' EXHIBIT NO. 37 (REVISED)
15 PIPELINES
1962

	Pipelines	1962 Production Volume From Gas Wells (Mcf @ 14.65) (1)	Total Production and E and D Costs Per Mcf (2)	Weighted Average (3)
1.	Tennessee Gas Transmission Company	24,733,652	111.84¢ 1/	
2.	New York State Natural Gas Corporation	8,139,628	66.62	
3.	El Paso Natural Gas Company	88,542,214	46.18	
4.	Hope Natural Gas Company	31,826,194	29.88	
5.	Texas Eastern Transmission Corporation	55,287,559	26.33	
6.	United Fuel Gas Company	54,303,833	24.11	
7.	Mountain Fuel Supply Company	23,467,593	20.42	
8.	Mississippi River Fuel Corporation	24,203,890	19.28	
9.	Southern Natural Gas Company	15,460,450	18.47	
10.	Arkansas Louisiana Gas Company	48,508,743	13.33	
11.	Panhandle Eastern Pipe Line Company	74,199,743	8.97	
12.	Kansas-Nebraska Natural Gas Company	28,928,337	8.71	
13.	Humble Gas Transmission Company	31,594,598	7.69	
14.	Colorado Interstate Gas Company	106,065,642	3.15	
15.	Natural Gas Pipeline Company of America	44,457,044	2.63	
	Total Production	659,719,120		
	Weighted Average - 15 Pipelines			22.13¢

1/ Corrected for error as shown at transcript page 2625.

[6033]

[6033]

Exhibit No. 58 (WRF-1)
Schedule 20
Page 2 of 4

COMPUTATION OF WEIGHTED AVERAGE COSTS
BY GROUP FOR ALL COMPANIES SHOWN ON
J. C. JONES' EXHIBIT NO. 37 (REVISED)
17 AFFILIATES
1962

Affiliates	1962 Production Volume From Gas Wells (Mcf @ 14.65) (1)	Total Production and E and D Costs Per Mcf (2)	Weighted Average (3)
1. Northwest Production Company	2,865,166	82.60¢	
2. Odessa Natural Gasoline Company	576,168	38.24	
3. Preston Oil Company	1,577,947	33.86	
4. Cities Service Production Company	15,660,044	23.81	
5. El Paso Natural Gas Products Company	2,029,992	23.63	
6. Tenneco Oil Company	37,869,237	20.78	
7. Texas Gas Exploration Corporation	14,039,958	17.80	
8. Colorado Oil and Gas Corporation	11,054,349	17.51	
9. Lone Star Producing Company	61,676,249	15.99	
10. Southern Natural Gas Joint Venture	9,115,772	15.36	
11. La Gloria Oil and Gas Company	2,167,269	14.95	
12. Anadarko Production Company	28,466,300	13.75	
13. Union Producing Company	173,005,657	12.95	
14. Pecos Company	1,115	9.87	
15. Cities Service Oil Company	103,123,512	9.45	
16. Columbian Fuel Corporation	34,594,293	8.10	
17. Cities Service Company	21,679,842	6.08	
Total Production	519,502,870		
Weighted Average - 17 Affiliates			13.74¢

[6034]

Exhibit No. 58 (WRF-1)
Schedule 20
Page 3 of 4

COMPUTATION OF WEIGHTED AVERAGE COSTS
BY GROUP FOR ALL COMPANIES SHOWN ON
J. C. JONES' EXHIBIT NO. 37 (REVISED)
54 INDEPENDENT PRODUCERS
1962

Independent Producers	1962 Production Volume From Gas Wells (Mcf @ 14.65) (1)	Total Production and E and D Costs Per Mcf (2)	Weighted Average (3)
1. Texoma Production Company	1,712,075	83.73¢	
2. Coastal State Gas Production Company	11,813,292	32.98	
3. Hassie Hunt Trust	5,308,723	32.44	
4. Signal Oil and Gas Company	5,134,608	24.31	
5. Cabot Corporation	37,128,860	23.20	
6. Forest Oil Corporation	19,799,638	23.09	
7. Southwest Gas Producing Company	10,556,075	23.05	
8. British-American Oil Producing Company	15,498,396	22.13	
9. Hugoton Plains Gas and Oil Company	14,172,007	21.38	
10. The Superior Oil Company	150,850,857	20.22	
11. Sinclair Oil and Gas Company	137,542,191	19.81	
12. Dorchester Gas Producing Company	22,446,943	19.75	
13. Magna Oil Corporation	10,072,523	19.26	
14. California Company	52,842,557	18.59	
15. Placid Oil Company	19,986,360	18.17	
16. Belco Petroleum Corporation	27,755,881	17.99	
17. Joseph E. Seagram and Sons, Inc.	7,113,259	17.98	
18. The Pure Oil Company	65,809,534	17.39	
19. Shell Oil Company	212,043,024	17.36	
20. Skelly Oil Company	71,669,654	16.83	
21. Delhi-Taylor Oil Corporation	30,556,679	16.79	
22. American Petrofina Company of Texas	8,195,366	16.43	
23. J. M. Huber Corporation	27,034,164	16.42	
24. Continental Oil Company	93,583,125	15.79	
25. Humble Oil and Refining Company	430,839,501	15.02	
26. General American Oil Company of Texas	18,131,582	15.01	
27. Sun Oil Company	130,281,986	14.67	
28. Standard Oil Company of Texas	70,101,276	14.49	
29. Socony Mobil Oil Company, Inc.	244,850,750	13.81	
30. Pan American Petroleum Corporation	406,191,535	13.75	
31. Texas Gulf Producing Company	6,827,411	13.69	
32. Amerada Petroleum Corporation	35,117,707	13.53	
33. Atlantic Refining Company	142,181,566	13.32	
34. Sunray DX Oil Company	87,997,186	12.95	

[6035]

Exhibit No. 58 (WRF-1)
Schedule 20
Page 4 of 4

COMPUTATION OF WEIGHTED AVERAGE COSTS
BY GROUP FOR ALL COMPANIES SHOWN ON
J. C. JONES' EXHIBIT NO. 37 (REVISED)
54 INDEPENDENT PRODUCERS
1962

Independent Producers (continued)	1962 Production Volume From Gas Wells (Mcf @ 14.65) (1)	Total Production and E and D Costs Per Mcf (2)	Weighted Average (3)
35. Murphy Corporation	17,330,709	12.48¢	
36. Phillips Petroleum Corporation	362,309,837	12.34	
37. Union Texas Petroleum	72,028,692	12.22	
38. Western Natural Gas Company	32,077,253	12.08	
39. United Carbon Company	79,039,000	12.06	
40. Marathon Oil Company	76,044,079	11.97	
41. Tidewater Oil Company	108,280,593	11.52	
42. Gulf Oil Corporation	218,108,732	11.38	
43. Kerr-McGee Oil Industries	56,179,867	11.34	
44. Hunt Oil Company	31,361,272	11.32	
45. Texaco Inc.	277,317,163	10.90	
46. Sohio Petroleum Company	32,977,257	10.85	
47. Union Oil Company of California	159,347,622	10.70	
48. Champlin Oil and Refining Company	70,559,408	9.52	
49. Northern Natural Gas Producing Company	56,420,765	9.14	
50. Shamrock Oil and Gas Corporation	72,958,573	8.78	
51. Mayfair Minerals, Inc.	18,343,582	7.09	
52. Tascosa Gas Company	7,989,480	5.10	
53. Panhandle Producing Company	3,342,176	2.50	
54. Continental Gas Producing Company	44,363,727	1.83	
Total Production	4,417,526,078		
Weighted Average - 54 Independents			13.99¢
Total Production - All Companies	5,596,748,068		
Weighted Average - All Companies			14.93¢

Source: Column (1) - Pipeline Production Group Witness Jones' Exhibit No. 37 (Revised), column (3)
Column (2) - Pipeline Production Group Witness Jones' Exhibit No. 37 (Revised), column (10)
Column (3) - Column (2) weighted by column (1)

[6036]

Exhibit No. 58 (WRF-1)
Schedule 21
Page 1 of 4

COMPUTATION OF AVERAGE PERCENTAGE DEVIATION FROM WEIGHTED AVERAGE UNIT PRODUCTION AND EXPLORATION AND DEVELOPMENT COST PER MCF FOR ALL COMPANIES SHOWN ON J. C. JONES' EXHIBIT NO. 37 (REVISED)
15 PIPELINES
1962

	Pipelines	1962 Production Volume From Gas Wells (Mcf @ 14.65)	Total Production and E and D Costs Per Mcf	Percent Deviation From 14.93¢ Weighted Average For All Groups
		(1)	(2)	(3)
1.	Tennessee Gas Transmission Company	24,733,652	111.84¢	649.1%
2.	New York State Natural Gas Corporation	8,139,628	66.62 1/	346.2
3.	El Paso Natural Gas Company	88,542,214	46.18	209.3
4.	Hope Natural Gas Company	31,826,194	29.88	100.1
5.	Texas Eastern Transmission Corporation	55,287,559	26.33	76.4
6.	United Fuel Gas Company	54,303,833	24.11	61.5
7.	Mountain Fuel Supply Company	23,467,593	20.42	36.8
8.	Mississippi River Fuel Corporation	24,203,890	19.28	29.1
9.	Southern Natural Gas Company	15,460,450	18.47	23.7
10.	Arkansas Louisiana Gas Company	48,508,743	13.33	(10.7)
11.	Panhandle Eastern Pipe Line Company	74,199,743	8.97	(39.9)
12.	Kansas-Nebraska Natural Gas Company	28,928,337	8.71	(41.7)
13.	Humble Gas Transmission Company	31,594,598	7.69	(48.5)
14.	Colorado Interstate Gas Company	106,065,642	3.15	(78.9)
15.	Natural Gas Pipeline Company of America	44,457,044	2.63	(82.4)
	Total Production	659,719,120		
	Average Deviation From Weighted Average (ignoring signs) 2/			103.6%

1/ Corrected for error as shown at transcript page 2625.

2/ Weighted by column (1).

[6037]

Exhibit No. 58 (WRF-1)
Schedule 21
Page 2 of 4

COMPUTATION OF AVERAGE PERCENTAGE DEVIATION FROM WEIGHTED AVERAGE UNIT PRODUCTION AND EXPLORATION AND DEVELOPMENT COST PER MCF FOR ALL COMPANIES SHOWN ON J. C. JONES' EXHIBIT NO. 37 (REVISED)
17 PIPELINE AFFILIATES
1962

	Affiliates	1962 Production Volume From Gas Wells (Mcf @ 14.65) (1)	Total Production and E and D Costs Per Mcf (2)	Percent Deviation From 14.93¢ Weighted Average For All Groups (3)
1.	Northwest Production Company	2,865,166	82.60¢	453.2%
2.	Odessa Natural Gasoline Company	576,168	38.24	156.1
3.	Preston Oil Company	1,577,947	33.86	126.8
4.	Cities Service Production Company	15,660,044	23.81	59.5
5.	El Paso Natural Gas Products Company	2,029,992	23.63	58.3
6.	Tenneco Oil Company	37,869,237	20.78	39.2
7.	Texas Gas Exploration Corporation	14,039,958	17.80	19.2
8.	Colorado Oil and Gas Corporation	11,054,349	17.51	17.3
9.	Lone Star Producing Company	61,676,249	15.99	7.1
10.	Southern Natural Gas Joint Venture	9,115,772	15.36	2.9
11.	La Gloria Oil and Gas Company	2,167,269	14.95	.1
12.	Anadarko Production Company	28,466,300	13.75	(7.9)
13.	Union Producing Company	173,005,657	12.95	(13.3)
14.	Pecos Company	1,115	9.87	(33.9)
15.	Cities Service Oil Company	103,123,512	9.45	(36.7)
16.	Columbian Fuel Corporation	34,594,293	8.10	(45.7)
17.	Cities Service Company	21,679,842	6.08	(59.3)
	Total Production	519,502,870		
	Average Deviation From Weighted Average (ignoring signs) 1/			27.4%

1/ Weighted by column (1).

[6038]

Exhibit No. 58 (WRF-1)
Schedule 21
Page 3 of 4

COMPUTATION OF AVERAGE PERCENTAGE DEVIATION FROM WEIGHTED AVERAGE UNIT PRODUCTION AND EXPLORATION AND DEVELOPMENT COST PER MCF FOR ALL COMPANIES SHOWN ON J. C. JONES' EXHIBIT NO. 37 (REVISED)
54 INDEPENDENT PRODUCERS
1962

	Independent Producers	1962 Production Volume From Gas Wells (Mcf @ 14.65)	Total Production and E and D Costs Per Mcf	Percent Deviation From 14.93¢ Weighted Average For All Groups
		(1)	(2)	(3)
1.	Texoma Production Company	1,712,075	83.73¢	460.8%
2.	Coastal State Gas Production Company	11,813,292	32.98	120.9
3.	Hassie Hunt Trust	5,308,723	32.44	117.3
4.	Signal Oil and Gas Company	5,134,608	24.31	62.8
5.	Cabot Corporation	37,128,860	23.20	55.4
6.	Forest Oil Corporation	19,799,638	23.09	54.7
7.	Southwest Gas Producing Company	10,556,075	23.05	54.4
8.	British-American Oil Producing Company	15,498,396	22.13	48.2
9.	Hugoton Plains Gas and Oil Company	14,172,007	21.38	43.2
10.	The Superior Oil Company	150,850,857	20.22	35.4
11.	Sinclair Oil and Gas Company	137,542,191	19.81	32.7
12.	Dorchester Gas Producing Company	22,446,943	19.75	32.3
13.	Magna Oil Corporation	10,072,523	19.26	29.0
14.	California Company	52,842,557	18.59	24.5
15.	Placid Oil Company	19,986,360	18.17	21.7
16.	Belco Petroleum Corporation	27,755,881	17.99	20.5
17.	Joseph E. Seagram and Sons, Inc.	7,113,259	17.98	20.4
18.	The Pure Oil Company	65,809,534	17.39	16.5
19.	Shell Oil Company	212,043,024	17.36	16.3
20.	Skelly Oil Company	71,669,654	16.83	12.7
21.	Delhi-Taylor Oil Corporation	30,556,679	16.79	12.5
22.	American Petrofina Company of Texas	8,195,366	16.43	10.0
23.	J. M. Huber Corporation	17,034,164	16.42	10.0
24.	Continental Oil Company	93,583,125	15.79	5.8
25.	Humble Oil and Refining Company	430,839,501	15.02	.6
26.	General American Oil Company of Texas	18,131,582	15.01	.5
27.	Sun Oil Company	130,281,986	14.67	(1.7)
28.	Standard Oil Company of Texas	70,101,276	14.49	(3.0)
29.	Socony Mobil Oil Company, Inc.	244,850,750	13.81	(7.5)
30.	Pan American Petroleum Corporation	406,191,535	13.75	(7.9)
31.	Texas Gulf Producing Company	6,827,411	13.69	(8.3)
32.	Amerada Petroleum Corporation	35,117,707	13.53	(9.4)

[6039]

Exhibit No. 58 (WRF-1)
Schedule 21
Page 4 of 4

COMPUTATION OF AVERAGE PERCENTAGE DEVIATION FROM WEIGHTED AVERAGE UNIT PRODUCTION AND EXPLORATION AND DEVELOPMENT COST PER MCF FOR ALL COMPANIES SHOWN ON J. C. JONES' EXHIBIT NO. 37 (REVISED)
54 INDEPENDENT PRODUCERS
1962

Independent Producers (continued)	1962 Production Volume From Gas Wells (Mcf @ 14.65)	Total Production and E and D Costs Per Mcf	Percent Deviation From 14.93¢ Weighted Average For All Groups
	(1)	(2)	(3)
33. Atlantic Refining Company	142,181,566	13.32¢	(10.8)%
34. Sunray DX Oil Company	87,997,186	12.95	(13.3)
35. Murphy Corporation	17,330,709	12.48	(16.4)
36. Phillips Petroleum Corporation	362,309,837	12.34	(17.3)
37. Union Texas Petroleum	72,028,692	12.22	(18.2)
38. Western Natural Gas Company	32,077,253	12.08	(19.1)
39. United Carbon Company	79,039,000	12.06	(19.2)
40. Marathon Oil Company	76,044,079	11.97	(19.8)
41. Tidewater Oil Company	108,280,593	11.52	(22.8)
42. Gulf Oil Corporation	218,108,732	11.38	(23.8)
43. Kerr-McGee Oil Industries	56,179,867	11.34	(24.0)
44. Hunt Oil Company	31,361,272	11.32	(24.2)
45. Texaco Inc.	277,317,163	10.90	(27.0)
46. Sohio Petroleum Company	32,977,257	10.85	(27.3)
47. Union Oil Company of California	159,347,622	10.70	(28.3)
48. Champlin Oil and Refining Company	70,559,408	9.52	(36.2)
49. Northern Natural Gas Producing Company	56,420,765	9.14	(38.8)
50. Shamrock Oil and Gas Corporation	72,958,573	8.78	(41.2)
51. Mayfair Minerals, Inc.	18,343,582	7.09	(52.5)
52. Tascosa Gas Company	7,989,480	5.10	(65.8)
53. Panhandle Producing Company	3,342,176	2.50	(83.3)
54. Continental Gas Producing Company	44,363,727	1.83	(87.7)
Total Production	4,417,526,078		
Average Deviation From Weighted Average (ignoring signs) 1/			19.1 %

1/ Weighted by column (1).

Source: Columns (1) and (2) - Columns (3) and (10) of Pipeline Production Group Witness Jones' Exhibit No. 37 (Revised)

[6040]

Exhibit No. 58 (WRF-1)
Schedule 22

EXPLORATORY WELL SUCCESS RATIOS BASED ON
W. P. ANDERSON'S EXHIBIT NO. 25
(Comparison of 1955-1958 and 1959-1962)

	Pipeline Producers			Affiliated Producers			Independent Producers		
	Total Wells	Successful Wells	Percent Successful	Total Wells	Successful Wells	Percent Successful	Total Wells	Successful Wells	Percent Successful
1955	51.4	21.3	41.4%	74.9	24.2	32.3%	1,968.1	521.0	26.5%
1956	49.1	19.5	39.7	97.8	31.4	32.2	2,100.5	628.6	29.9
1957	48.2	17.5	36.3	121.2	34.3	28.3	2,016.0	601.6	29.8
1958	51.8	14.7	28.3	86.8	30.4	35.0	1,559.5	462.9	29.7
Total 1955-1958	200.5	73.0	36.4%	380.7	120.3	31.6%	7,644.1	2,214.1	29.0%
1959	27.9	12.2	43.9%	111.4	32.5	29.2%	1,800.9	560.5	31.1%
1960	54.1	9.8	18.0	91.9	25.1	27.4	1,583.7	477.5	30.2
1961	48.6	7.3	15.0	114.3	35.5	31.1	1,687.9	505.3	29.9
1962	36.6	14.3	39.2	135.4	41.4	30.6	1,688.4	495.0	29.3
Total 1959-1962	167.2	43.6	26.1%	453.0	134.5	29.7%	6,760.9	2,038.3	30.1%
Total 1955-1962	367.7	116.6	31.7%	833.7	254.8	30.6%	14,405.0	4,252.4	29.5%

Source: Pipeline Production Group Witness Anderson's Exhibit No. 25, pages 6, 11, and 27.

[6041]

Exhibit No. 58 (WRF-1)
Schedule 23

EXPLORATORY WELL SUCCESS RATIOS BASED ON
W. P. ANDERSON'S EXHIBIT NO. 25
1960 - 1962

	Total Wells	Successful Wells	Percent Successful
Pipeline Producers			
1960	54.1	9.8	18.0%
1961	48.6	7.3	15.0
1962	36.6	14.3	39.2
Total	139.3	31.4	22.5%
Affiliated Producers			
1960	91.9	25.1	27.4%
1961	114.3	35.5	31.1
1962	135.4	41.4	30.6
Total	341.6	102.0	29.9%
Independent Producers			
1960	1,583.7	477.5	30.2%
1961	1,687.9	505.3	29.9
1962	1,688.4	495.0	29.3
Total	4,960.0	1,477.8	29.8%

Source: Pipeline Production Group Witness Anderson's Exhibit No. 25, pages 6, 11, and 27.

[6042]

Exhibit No. 58 (WRF-1
Schedule 24

57
6042

SUMMARY OF EXPLORATORY WELL SUCCESS RATIOS BASED ON W. P. ANDERSON'S EXHIBIT NO. 25 NINE PIPELINES 1955 - 1962

	1955 - 1962				
				Company as Percent of Total	
	Total Wells (1)	Successful Wells (2)	Percent Successful (3)	Total Wells (4)	Successful Wells (5)
Colorado Interstate Gas Company	1.5	.0	0.0%	.4%	.0%
Humble Gas Transmission Company	13.6	4.5	32.9	3.7	3.9
Kansas-Nebraska Natural Gas Company	6.1	.0	0.0	1.7	.0
Mountain Fuel Supply Company	36.1	9.5	26.3	9.8	8.1
Panhandle Eastern Pipe Line Company	113.3	51.9	45.8	30.8	44.5
Southern Natural Gas Company	54.0	9.3	17.2	14.7	8.0
Tennessee Gas Transmission Company	10.3	5.3	51.6	2.8	4.5
Texas Eastern Transmission Corporation	64.7	11.2	17.3	17.6	9.6
United Fuel Gas Company	68.0	25.0	36.8	18.5	21.4
Total	367.6	116.7	31.7%	100.0%	100.0%
Excluding Panhandle Eastern	254.3	64.8	25.5%		
Excluding Panhandle Eastern and United Fuel	186.3	39.8	21.4%		

Source: Columns (1) and (2) - Pipeline Production Group Witness Anderson's Exhibit No.25, pages 3-5

Column (3) - Column (2) divided by column (1)
Column (4) - Company figure in column (1) divided by total figure in column (1)
Column (5) - Company figure in column (2) divided by total figure in column (2)

[6043]

Exhibit No. 58 (WRF-1)
Schedule 25

SUMMARY OF EXPLORATORY WELL SUCCESS RATIOS
BASED ON W. P. ANDERSON'S EXHIBIT NO. 25
NINE PIPELINES
1960-1962 AND 1962

	1960 - 1962					1962				
				Company as Percent of Total					Company as Percent of Total	
	Total Wells (1)	Successful Wells (2)	Percent Successful (3)	Total Wells (4)	Successful Wells (5)	Total Wells (6)	Successful Wells (7)	Percent Successful (8)	Total Wells (9)	Successful Wells (10)
Colorado Interstate Gas Company	1.0	.0	.0%	.7%	.0%	.5	.0	.0%	1.4%	.0%
Humble Gas Transmission Company	3.5	.0	.0	2.5	.0	.6	.0	.0	1.6	.0
Kansas-Nebraska Natural Gas Company	1.1	.0	.0	.8	.0	.0	.0	-	.0	.0
Mountain Fuel Supply Company	17.2	5.6	32.6	12.4	17.8	9.3	4.0	43.0	25.5	27.8
Panhandle Eastern Pipe Line Company	41.8	6.5	15.6	30.0	20.6	7.6	3.0	39.5	20.8	20.8
Southern Natural Gas Company	25.3	7.2	28.5	18.2	22.9	11.3	5.1	45.1	31.0	35.4
Tennessee Gas Transmission Company	7.0	3.0	42.9	5.0	9.5	2.0	1.0	50.0	5.5	6.9
Texas Eastern Transmission Corporation	19.3	4.2	21.8	13.9	13.3	1.2	.3	25.0	3.3	2.1
United Fuel Gas Company	23.0	5.0	21.7	16.5	15.9	4.0	1.0	25.0	11.0	6.9
Total	139.2	31.5	22.6%	100.0%	100.0%	36.5	14.4	39.5	100.0%	100.0%

Source: Columns (1), (2), (6) and (7) - Pipeline Production Group Witness Anderson's Exhibit No. 25, pages 3-5
Column (3) - Column (2) divided by column (1)
Column (4) - Company figure in column (1) divided by total figure in column (1)
Column (5) - Company figure in column (2) divided by total figure in column (2)
Column (8) - Column (7) divided by column (6)
Column (9) - Company figure in column (6) divided by total figure in column (6)
Column (10) - Company figure in column (7) divided by total figure in column (7)

[6044]

Exhibit No. 58 (WRF-1)
Schedule 26
Page 1 of 4

EXPLORATORY WELL DRILLING RESULTS BY STATE
PER AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS
1962

	New-Field Wildcat Holes				Total Exploratory Holes 1/			
	Producers (1)	Dry (2)	Total (3)	Percent Producers (4)	Producers (5)	Dry (6)	Total (7)	Percent Producers (8)
Total United States	787	6,007	6,794	11.6%	1,982	8,815	10,797	18.4%
Alabama	0	11	11	0.0	1	11	12	8.3
Alaska	2	18	20	10.0	2	22	24	8.3
Arizona	1	33	34	2.9	1	36	37	2.7
Arkansas	6	54	60	10.0	34	85	119	28.6
California	14	212	226	6.2	50	366	416	12.0
Colorado	26	358	384	6.8	46	406	452	10.2
Florida	0	3	3	0.0	0	3	3	0.0
Georgia	0	2	2	0.0	0	2	2	0.0
Illinois	10	211	221	4.5	44	477	521	8.4
Indiana	16	266	282	5.7	66	488	554	11.9
Kansas	60	508	568	10.6	163	794	957	17.0
Kentucky	13	130	143	9.1	28	218	246	11.4
Louisiana	60	628	688	8.7	140	841	981	14.3
South	43	322	365	11.8	103	498	601	17.1
North	17	306	323	5.3	37	343	380	9.7
Maryland	0	0	0	-	0	1	1	0.0
Michigan	10	249	259	3.9	15	281	296	5.1
Mississippi	11	131	142	7.7	40	245	285	14.0
Missouri	0	10	10	0.0	0	10	10	0.0
Montana	7	119	126	5.6	20	164	184	10.9
Nebraska	25	357	382	6.5	30	371	401	7.5
Nevada	0	10	10	0.0	0	11	11	0.0
New Mexico	31	210	241	12.9	67	275	342	19.6
New York	5	31	36	13.9	23	40	63	36.5
North Dakota	2	75	77	2.6	4	85	89	4.5
Ohio	6	74	80	7.5	60	116	176	34.1
Oklahoma	61	183	244	25.0	257	546	803	32.0
Oregon	0	6	6	0.0	0	6	6	0.0

[6061]

[6061]

Exhibit No. 58 (WRF-1)
Schedule 35

COMPARISON OF INDIVIDUAL PIPELINE PRODUCTION UNIT COSTS
PER R. D. MURR'S EXHIBIT, ITEM I BY REFERENCE
1962

	Pipeline	Production Volume (Mcf) (1)	Production Unit Costs (2)	Percent Deviation From 12.18¢ Weighted Average (3)
1.	Tennessee Gas Transmission Company	24,733,652	53.9972¢	343.3 %
2.	Kentucky West Virginia Gas Company	27,676,337	24.3891	100.2
3.	New York State Natural Gas Corporation	8,139,628	24.0809	97.7
4.	El Paso Natural Gas Company	88,542,214	23.1674	90.2
5.	Texas Eastern Transmission Corporation	55,287,559	19.4136	59.4
6.	United Fuel Gas Company	54,303,833	15.1719	24.6
7.	Mississippi River Fuel Corporation	24,203,890	8.1966	(32.7)
8.	Arkansas Louisiana Gas Company	48,508,743	7.9913	(34.4)
9.	Mountain Fuel Supply Company	23,467,593	7.7308	(36.5)
10.	Southern Natural Gas Company	15,460,450	6.6905	(45.1)
11.	Panhandle Eastern Pipe Line Company	74,199,743	5.4835	(55.0)
12.	Humble Gas Transmission Company	31,594,598	4.2045	(65.5)
13.	Kansas-Nebraska Natural Gas Company	28,928,337	3.3712	(72.3)
14.	Colorado Interstate Gas Company	106,065,642	2.2815	(81.3)
15.	Natural Gas Pipeline Company of America	44,457,044	1.8560	(84.8)
	Total Production	655,569,263		
	Weighted Average		12.18 ¢	

Source: Columns (1) and (2) - Sheet 3 of Schedule 1 of FPC Staff Witness Murr's Exhibit No. 60-J in Docket Nos. AR64-1 and AR64-2, Item I by reference in this proceeding

Column (3) - [Column (2) divided by 12.18¢] minus 100.0%

[6062]

Exhibit No. 58 (WRF-1)
Schedule 36

COMPARISON OF INDIVIDUAL PIPELINE PRODUCTION AND EXPLORATION AND DEVELOPMENT UNIT COSTS PER J. C. JONES' EXHIBIT NO. 37 (REVISED)
1962

Pipeline	Production Volume (Mcf) (1)	Production and E and D Unit Costs (2)	Percent Deviation From 22.13¢ Weighted Average (3)
1. Tennessee Gas Transmission Company	24,733,652	111.84¢	405.4 %
2. New York State Natural Gas Company	8,139,628	66.62 1/	201.0
3. El Paso Natural Gas Company	88,542,214	46.18	108.7
4. Hope Natural Gas Company	31,826,194	29.88	35.0
5. Texas Eastern Transmission Corporation	55,287,559	26.33	19.0
6. United Fuel Gas Company	54,303,833	24.11	8.9
7. Mountain Fuel Supply Company	23,467,593	20.42	(7.7)
8. Mississippi River Fuel Corporation	24,203,890	19.28	(12.9)
9. Southern Natural Gas Company	15,460,450	18.47	(16.5)
10. Arkansas Louisiana Gas Company	48,508,743	13.33	(39.8)
11. Panhandle Eastern Pipe Line Company	74,199,743	8.97	(59.5)
12. Kansas-Nebraska Natural Gas Company	28,928,337	8.71	(60.7)
13. Humble Gas Transmission Company	31,594,598	7.69	(65.3)
14. Colorado Interstate Gas Company	106,065,642	3.15	(85.8)
15. Natural Gas Pipeline Company of America	44,457,044	2.63	(88.1)
Total Production	659,719,120		
Weighted Average		22.13¢	

1/ Corrected for error as shown at transcript page 2625.

Source: Columns (1) and (2) - Pipeline Production Group Witness Jones' Exhibit No. 37 (Revised)

Column (3) - [Column (2) divided by 22.13¢] minus 100.0%

[6122]

EXHIBIT NO. 59
Witness: Kenneth L. Smith

DOCKET NO. RP66-24

PIPELINE PRODUCTION AREA RATE PROCEEDING

Pipeline Production Cost Arrays for
D D & A and Return at 6.5%
Year 1962

Line No.	Name of Pipeline Company	Percentage of Total Production	Unit Costs (cents per Mcf) D D & A	Unit Costs (cents per Mcf) Return
	(1)	(2)	(3)	(4)
1	Natural Gas Pipeline Company of America	6.781%	0.4581	0.6160
2	Colorado Interstate Gas Co.	16.179	0.5712	0.8470
3	Panhandle Eastern Pipe Line Co.	11.318	0.6844	1.4795
4	Kansas-Nebraska Natural Gas Co.	4.413	1.0653	1.6529
5	Arkansas-Louisiana Gas Co.	7.400	1.8089	2.0557
6	Humble Gas Transmission Co.	4.819	1.9183	1.0803
7	Southern Natural Gas Co.	2.358	2.3955	2.2697
8	Mountain Fuel Supply Co.	3.580	3.0908	3.1849
9	Mississippi River Fuel Corp.	3.692	3.2497	2.8552
10	El Paso Natural Gas Co.	13.506	4.5089*	16.9026*
11	United Fuel Gas Co.	8.284	6.1504*	4.9878
12	Kentucky West Virginia Gas Co.	4.222	8.7536*	6.2813*
13	New York State Natural Gas Corp.	1.241	11.1706*	6.7558*
14	Tennessee Gas Pipeline Co.	3.773	11.2305*	40.6470*
15	Texas Eastern Transmission Corp.	8.434	12.9279*	3.9798
16	All above companies	100.000		
17	Weighted average		3.9022	5.8110
18	Composite		4.0047	6.0231

*Unit cost exceeds weighted average unit cost.

[6123]

EXHIBIT NO. 60
Witness: Kenneth L. Smith

DOCKET NO. RP66-24

PIPELINE PRODUCTION AREA RATE PROCEEDING

Cross References to Data (Years 1955-62)
Supplementing Pipeline Company Data
Included in Exhibit No. 21

Item No.	Type of Data (1)	Reference Exhibit No. 21 (2)	Cross References to Staff Exhibits: Ex. No. 5 (3)	Cross References to Staff Exhibits: Ex. No. 6 (4)	Cross References to Composites (5)
1	Exploration and Development Investment	Sch. 1, Cols. (3) and (10)			Vol. 1, p. 41 1/
2	Owned Gas Reserves	Sch. 1, Cols. (4) and (11)		page 3, Col. (d)	
3	Acquisitions - Investment	Sch. 2	Sch. 3, lines 1 to 7		
4	Acquisitions - Gas Reserves	Sch. 2			Vol. 1, p. 17 (Revised)
5	Exploration and Development Costs	Sch. 4	page 7		Vol. 1, p. 42
	Transfers from Non-Producing to Producing				
6	Acres	Sch. 5			Vol. 1, p. 16, (Revised)
7	Cost	Sch. 5	Sch. 7, line 4		-
8	Gas Produced	Sch. 6 Col. (3)		page 23, lines 2 to 9	-

1/ The Staff's composite "Manually Revised Schedules" do not agree with page 41; the differences are not significant, however.

Docket No. RP66-24

Exhibit 62

Witness: J. M. Johnson, Jr.

RECENT OFFERINGS OF NATURAL GAS PIPELINES AND
INDEPENDENT PRODUCER DEBT

Line No.	Company	Issue	Offering Date	Principal Amount in Millions	Moody's Rating at Offering	Net Proceeds to Company Amount	Net Proceeds to Company Cost
1	NATURAL GAS PIPELINES:						
2	Northern Natural Gas Company	Debentures, 5-3/4%, 1986	June, 1966	$ 50.0	A	$ 99.20	5.82%
3	Trunkline Gas Company	First mortgage pipeline bonds, 6-1/2%, 1986	August, 1966	40.0	A	99.05	6.[illegible]
4	Natural Gas Pipeline Company of America	First mortgage pipeline bonds, 6-1/4%, 1986	August, 1966	40.0	Aa	98.13	6.42%
5	Panhandle Eastern Pipeline Company	Debentures, 5-3/4%, 1987	March, 1967	40.0	A	99.15	5.[illegible]
6	Northern Natural Gas Company	Debentures, 5-7/8%, 1987	April, 1967	50.0	A	99.13	5.95%
7	Southern Natural Gas Company	First mortgage pipeline bonds, 5-5/8%, 1987	April, 1967	40.0	Aa	99.13	5.70%
8	Michigan-Wisconsin Pipe Line Company	First mortgage pipeline bonds, 6-3/4%, 1987	May, 1967	45.0	A	100.38	6.72%
9	Lone Star Gas Company	Debentures, 6-1/8%, 1992	June, 1967	30.0	A	99.53	6.1[illegible]
10	Mountain Fuel Supply Company	Debentures, 6-1/4%, 1992	June, 1967	20.0	A	99.75	6.29%
11	Natural Gas Pipeline Company of America	First mortgage pipeline bonds, 6%, 1987	July, 1967	40.0	Aa	98.55	6.13%
12	Panhandle Eastern Pipeline Company	Debentures, 6-1/2%, 1987	October, 1967	40.0	A	98.13	6.67%
13	Northern Natural Gas Company	Debentures, 6-7/8%, 1987	November, 1967	40.0	A	98.13	7.05%
14	Natural Gas Pipeline Company of America	First mortgage pipeline bonds, 6-3/4%, 1987	December, 1967	50.0	Aa	98.13	6.93%
15	INDEPENDENT PRODUCERS:						
16	Gulf Oil Corporation	Debentures, 5.35%, 1991	June, 1966	$100.0	Aaa	$ 99.125	5.42%
17	Standard Oil of Indiana	Debentures, 6%, 1991	September, 1966	175.0	Aaa	99.125	6.07%
18	Shell Oil Company	Debentures, 5.30%, 1992	March, 1967	150.0	Aaa	98.875	5.39%
19	Atlantic Richfield Company	Debentures, 5-5/8%, 1997	May, 1967	100.0	Aa	99.125	5.69%
20	Texaco, Inc.	Debentures, 5-3/4%, 1997	July, 1967	200.0	Aaa	99.125	5.81%
21	Standard Oil of Indiana	Debentures, 6%, 1998	January, 1968	200.0	Aaa	98.125	6.14%

[6126]

[6141]

EXHIBIT NO. 67 (MFW-1)
DOCKET NO. RP66-24

PIPELINE PRODUCTION GROUP

CAPITALIZATION OF INDEPENDENT PRODUCERS, PIPELINE PRODUCERS, AFFILIATE PRODUCERS 1962, 1966.

[6142]

INDEX

[6143]

SCHEDULE 1

Capitalization Ratios and Cost of Capital Using Arithmetic Averages and Estimated Future Debt Cost

December 31, 1966

I. PRODUCING PIPELINES 1/

Long-Term Debt	47.31% × 6.50% =	3.08%
Preferred	3.34% × 5.50% =	.18%
Common	49.35% × r =	?
	100.00%	Return

Where r is return on equity and:
Overall return is 6.25%; then r = 6.06%
Overall return is 6.50%; then r = 6.57
Overall return is 7.00%; then r = 7.56
Overall return is 10.50%; then r = 14.67
Overall return is 12.00%; then r = 17.71
Overall return is 16.00%; then r = 25.82

SOURCE: F.P.C. Statistics of Natural Gas Pipelines - 1966

* *

II. NATIONAL GROUP - INDEPENDENT PRODUCERS 2/

Long-Term Debt	21.86% × 6.00% =	1.31%
Preferred	1.61% × 5.00% =	.08
Common	76.53% × r =	?
	100.00%	Return

Where r is return on equity and:
Overall return is 6.25%; then r = 6.35%
Overall return is 6.50%; then r = 6.68
Overall return is 7.00%; then r = 7.33
Overall return is 10.50%; then r = 11.90
Overall return is 12.00%; then r = 13.86
Overall return is 16.00%; then r = 19.09

SOURCE: Moody's Industrial Manual - June 1967

1/ Group I of list of respondents attached to the F.P.C. Staff's letter to all respondents dated 4/25/67.

2/ List of Independent Producers used by Felix J. Shaffner in his direct testimony.

[6144]

SCHEDULE 2

Producing Pipeline Companies' Capitalization Ratios and Cost of Debt and Preferred Stock
December 31, 1966

	Percent of Total Capitalization				Average Cost of	
	Long Term Debt	Preferred Stock	Common Equity	Total Capitalization	Debt*	Preferred Stock*
Humble Gas Transmission	- %	- %	100.00%	100.00%	-	-
Kentucky-West Virginia Gas Co.	-	-	100.00	100.00	-	-
United Natural Gas Co.	22.25	-	77.75	100.00	4.59	-
Cities Service Gas Co.	26.70	1.47	71.83	100.00	4.14	5.00
Kentucky Gas	30.72	-	69.28	100.00	3.51	-
Pennsylvania Gas Co.	37.72	-	62.28	100.00	4.90	-
Iroquois Gas Corp.	41.75	-	58.25	100.00	5.04	-
Southern Natural Gas Co.	44.27	-	55.73	100.00	4.36	-
United Fuel & Gas Co.	47.53	-	52.47	100.00	4.71	-
Consolidated Gas Supply Corp.	48.96	-	51.04	100.00	4.37	-
Ohio Fuel Gas Co.	50.55	-	49.45	100.00	4.50	-
Cumberland & Allegheny	51.23	-	48.77	100.00	4.46	-
Manufacturers Light & Heat	51.92	-	48.08	100.00	4.57	-
United Gas Pipe Line Co.	52.99	-	47.01	100.00	4.53	-
Atlantic Seaboard Corp.	53.91	-	46.09	100.00	4.82	-
Lone Star Gas Co.	55.68	-	44.32	100.00	4.24	-
Alabama Tennessee Nat. Gas Co.	59.70	-	40.30	100.00	4.95	-
Texas Gas Transmission Corp.	57.38	3.76	38.86	100.00	4.88	5.17
Kansas-Nebraska Nat. Gas Co.	50.91	11.89	37.20	100.00	4.58	5.11
Mississippi River Trans. Corp.	63.13		36.87	100.00	5.00	-
Nat. Gas Pipeline Co. of Amer.	58.87	7.20	33.93	100.00	4.83	4.77
Panhandle Eastern P.L. Co.	60.80	6.25	32.95	100.00	4.18	4.54
Colorado Interstate Gas Co.	57.16	10.58	32.26	100.00	4.70	5.20
Trunkline Gas Co.	63.24	9.54	27.22	100.00	5.19	4.89
Tenneco	56.95	17.39	25.66	100.00	4.44	5.05
El Paso Natural Gas Co.	68.36	9.20	22.44	100.00	4.93	5.05
Texas Eastern Trans. Corp.	64.81	12.86	22.33	100.00	4.85	5.31
Averages	47.31%	3.34%	49.35%	100.00%	4.61%	5.01%
Weighted Averages					4.65%	5.06%

SOURCE: F.P.C. Statistics for Interstate Natural Gas Pipeline Companies - 1966.

* Based on estimates where complete data was not available.

SCHEDULE 3

Independent Producers Capitalization Ratios and Cost of Debt and Preferred Stock 1966

	Percent of Total Capitalization				Average Cost of	
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization	Debt *	Preferred Stock *
Amerada Petroleum Corp.	- %	- %	100.00%	100.00%	- %	- %
Midwest Oil Co.	-	-	100.00	100.00	-	-
Aztec Oil & Gas Co.	4.38	-	95.62	100.00	5.00	-
Skelly Oil Co.	9.11	-	90.89	100.00	4.00	-
Standard Oil of Calif	9.68	-	90.32	100.00	4.56	-
Mobil Oil Corp	11.00	-	89.00	100.00	4.19	-
Gulf Oil Co.	14.63	-	85.37	100.00	3.71	-
Gen. Amer. Oil of Texas	14.76	-	85.24	100.00	4.75	-
Standard Oil of Ind.	15.37	-	84.63	100.00	4.40	-
Sunray DX Oil Co.	15.37	-	84.63	100.00	4.09	-
Standard Oil of N.J.	15.58	-	84.42	100.00	3.91	-
Texaco Oil Co.	15.87	-	84.13	100.00	4.17	-
Tidewater Oil Co.	10.65	6.75	82.60	100.00	3.63	4.80
Atlantic Richfield	17.05	2.98	79.97	100.00	3.51	3.75
Superior Oil Co.	20.17	-	79.83	100.00	4.18	-
Sun Oil	21.28	-	78.72	100.00	4.97	-
Sinclair Oil Co.	22.00	-	78.00	100.00	4.18	-
Shell Oil Co.	22.79	-	77.21	100.00	4.50	-
Marathon Oil Co.	22.85	-	77.15	100.00	4.56	-
Standard Oil of Ohio	[illegible].05	[illegible].39	75.56	100.00	4.63	3.86
Continental Oil Co.	24.89	.48	74.63	100.00	4.16	-
Cities Service Oil Co.	25.20	1.14	73.66	100.00	4.32	-
Union Oil of Calif.	23.86	6.86	69.28	100.00	4.28	-
Phillips Pet. Co.	36.75	-	63.25	100.00	5.00	-
Kerr-McGee Oil Co.	37.84	-	62.16	100.00	5.00	-
Shamrock Oil & Gas Corp.	40.88	-	59.12	100.00	4.55	-
Murphy Oil Co.	32.99	9.99	57.02	100.00	4.34	5.03
Signal Oil & Gas Co.	31.61	11.88	53.51	100.00	5.07	4.46
Helmerich & Payne	51.09	-	48.91	100.00	5.67	-
Coastal States Gas Prod. Co.	68.99	-	31.01	100.00	5.25	-
Total	21.86%	1.61%	76.53%	100.00%	4.45%	4.38%

SOURCE: Moody's Industrial Manual - June 1967.

[6145]

[6145]

[6146]

SCHEDULE 4

Producing Pipeline Companies' Capitalization
December 31, 1966

	Amounts in Thousands of Dollars			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Humble Gas Transmission Co.	$ -	$ -	$ 16,910	$ 16,910
Kentucky-West Virginia Gas Co.	-	-	28,296	28,296
United Natural Gas Co.	12,131	-	42,398	54,529
Cities Service Gas Co.	43,512	2,400	117,075	162,987
Kentucky Gas Transmission	4,128	-	9,310	13,438
Pennsylvania Gas Co.	14,800	-	24,434	39,234
Iroquois Gas Corp.	59,090	-	82,436	141,526
Southern Natural Gas Co.	102,511	-	129,046	231,557
United Fuel Gas Co.	89,133	-	98,383	187,516
Consolidated Gas Supply Corp.	173,925	-	181,324	355,249
Ohio Fuel Gas Co.	88,848	-	86,923	175,771
Cumberland & Allegheny	6,891	-	6,560	13,451
Manufacturers Light & Heat	76,984	-	71,303	148,287
United Gas Pipe Line Co.	195,704	-	173,589	369,293
Atlantic Seaboard Corp.	55,810	-	47,715	103,525
Lone Star Gas Co.	224,873	-	179,007	403,880
Alabama-Tennessee Nat. Gas Co.	4,407	-	2,975	7,382
Texas Gas Transmission Corp.	145,699	9,541	98,674	253,914
Kansas-Nebraska Nat. Gas Co.	35,858	8,375	26,201	70,434
Mississippi River Trans. Corp.	27,934	-	16,316	44,250
Nat. Gas Pipeline Co. of Amer.	314,076	38,400	181,020	533,496
Panhandle Eastern P.L. Co.	225,783	23,223	122,370	371,376
Colorado Interstate Gas Co.	100,769	18,657	56,868	176,294
Trunkline Gas Co.	144,550	21,800	62,216	228,566
Tenneco	1,106,038	337,729	498,234	1,942,001
El Paso Natural Gas Co.	794,149	106,924	260,619	1,161,692
Texas Eastern Trans. Corp.	612,953	121,617	211,176	945,746
Combined Totals	$4,660,556	$688,666	$2,831,378	$8,180,600
Composite Ratios	56.97%	8.42%	34.61%	100.00%

SOURCE: F.P.C. Statistics of Natural Gas Pipeline Companies - 1966

[6147]

Independent Producers Capitalization
1966

	Amounts in Thousands of Dollars			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Amerada Petroleum Corp.	-	-	323,876	323,876
Midwest Oil Co.	-	-	72,957	72,957
Aztec Oil & Gas Co.	1,800	-	39,273	41,073
Skelly Oil Co.	42,264	-	421,521	463,785
Standard Oil of Calif.	376,431	-	3,512,653	3,889,084
Mobil Oil Corp.	454,450	-	3,676,065	4,130,515
Gulf Oil Co.	736,502	-	4,298,301	5,034,803
Gen. Amer. Oil of Texas	20,512	-	118,448	138,960
Standard Oil of Ind.	518,960	-	2,857,349	3,376,309
Sunray DX Oil Co.	87,456	-	481,577	569,033
Standard Oil of N.J.	1,730,550		9,375,604	11,106,154
Texaco Oil Co.	853,567	-	4,525,478	5,379,045
Tidewater Oil Co.	90,015	56,999	697,991	845,005
Atlantic Richfield	256,616	44,924	1,203,932	1,505,472
Superior Oil Co.	73,584	-	291,262	364,846
Sun Oil	254,164	-	940,021	1,194,185
Sinclair Oil Co.	407,782	-	1,445,939	1,853,721
Shell Oil Co.	560,107	-	1,897,934	2,458,041
Marathon Oil Co.	165,832	-	559,860	725,692
Standard Oil of Ohio	100,97[illegible]	28,[illegible]8[illegible]	400,615	530,[illegible]76
Continental Oil Co.	386,7[illegible]	7,447	1,159,731	1,553,895
Cities Service Oil Co.	368,826	16,[illegible]8[illegible]	1,077,813	1,463,321
Union Oil of Calif.	378,274	108,814	1,098,545	1,585,633
Phillips Pet. Co.	803,564	-	1,382,838	2,186,402
Kerr-McGee Oil Co.	118,678	-	194,934	313,612
Shamrock Oil & Gas Corp.	62,826	-	90,863	153,689
Murphy Oil Co.	65,307	19,767	112,853	197,927
Signal Oil & Gas Co.	164,379	77,407	278,323	520,109
Helmerich & Payne	18,814	-	18,013	36,827
Coastal States Gas Prod. Co.	179,976	-	80,886	260,862
Total	$9,278,927	$360,627	$42,635,455	$52,275,009
Composite Ratios	17.75%	.69%	81.56%	100.00%

[6148]

[6148]

Affiliated Producer Companies' Capitalization Ratios
December 31, 1966

	Percent of Total Capitalization			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Lone Star Producing	- %	- %	100.00%	100.00%
Union Producing Co.	11.67	-	88.33	100.00
Cities Service Oil Co.	19.06	-	80.94	100.00
Colorado Oil & Gas Co.	23.13	-	76.87	100.00
Tenneco Oil Co.	26.49	-	73.51	100.00
Anadarko Production Co	37.23	-	62.77	100.00
Preston Oil Co.	51.05	-	48.95	100.00
El Paso Products	49.29	3.09	47.62	100.00
La Gloria Oil & Gas	52.82	-	47.18	100.00
Texas Gas Exploration	54.27	-	45.73	100.00
Averages	32.50%	.31%	67.19%	100.00%

SOURCE: Information supplied by the individual companies.

[6149]

SCHEDULE 7

Producing Pipeline Companies' Capitalization Ratios and Cost of Debt and Preferred Stock
December 31, 1962

	Percent of Total Capitalization				Average Cost of	
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization	Debt*	Preferred Stock *
Humble Gas Transmission Co.	- %	- %	100.00%	100.00%	- %	- %
Kentucky-West Virginia Gas Co.	1.96	-	98.04	100.00	3.38	-
United Natural Gas Co.	22.33	-	77.67	100.00	4.64	-
Cumberland & Allegheny	27.38	-	72.62	100.00	4.31	-
Kentucky Gas Transmission	34.12	-	65.88	100.00	3.29	-
Pennsylvania Gas Co.	37.31	-	62.69	100.00	4.72	-
Iroquois Gas Corp.	37.96	-	62.04	100.00	4.92	-
Cities Service Gas Co.	40.23	-	59.77	100.00	3.86	-
United Fuel Gas Co.	48.57	-	51.43	100.00	4.62	-
Consolidated Gas Supply Corp	48.59	-	51.41	100.00	4.24	-
Ohio Fuel Gas Co.	49.11	-	50.89	100.00	4.31	-
Lone Star Gas Co.	49.39	.40	50.21	100.00	3.99	4.84
Atlantic Seaboard Corp.	54.26	-	45.74	100.00	4.74	-
Manufacturers Light & Heat	54.73	-	45.27	100.00	4.38	-
Southern Natural Gas Co.	56.21	-	43.79	100.00	4.23	-
Alabama Tennessee Nat. Gas Co.	58.40	-	41.60	100.00	4.77	-
United Gas Pipe Line Co.	59.47	-	40.53	100.00	4.48	-
Kansas-Nebraska Nat. Gas Co.	43.31	17.12	39.57	100.00	4.13	5.13
Colorado Interstate Gas Co.	46.24	15.06	38.70	100.00	4.03	5.19
Nat. Gas Pipeline Co. of Amer.	57.82	9.64	32.54	100.00	4.35	5.53
Panhandle Eastern P.L. Co.	61.92	9.40	28.68	100.00	3.79	4.46
Mississippi River Trans. Corp.	71.98	-	28.02	100.00	5.00	-
Texas Gas Transmission Corp.	62.99	10.56	26.45	100.00	4.75	5.22
Tenneco	61.66	13.06	25.28	100.00	3.87	4.86
Trunkline Gas Co.	63.34	13.58	23.08	100.00	4.54	5.36
El Paso Natural Gas Co.	68.17	9.99	21.84	100.00	4.54	5.34
Texas Eastern Trans. Corp.	63.22	16.15	20.63	100.00	4.71	5.56
Averages	47.43%	4.26%	48.31%	100.00%	4.31%	5.15%

SOURCE: F.P.C. Statistics of Natural Gas Pipeline Companies - 1962.

* Based on estimates where complete data was not available

SCHEDULE 8

Independent Producers [redacted] Capitalization Ratios and Cost of Debt and Preferred Stock
196[illegible]

	Percent of Total Capitalization				Average Cost of	
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization	Long-Term Debt *	Preferred Stock *
Amerada Petroleum Corp.	- %	- %	100.00%	100.00%	- %	- %
Midwest Oil Co.	-	-	100.00	100.00	-	-
Skelly Oil Co.	.42	-	99.58	100.00	2.75	-
Sun Oil	2.26	-	97.74	100.00	3.85	-
Standard Oil of Calif.	6.45	.71	92.84	100.00	4.35	3.30
Mobil Oil Co.	7.55	-	92.45	100.00	4.13	-
Gulf Oil Co.	8.02	-	91.98	100.00	3.65	-
Texaco Oil Co.	9.82	-	90.18	100.00	3.22	-
Aztec Oil & Gas Co.	10.43	-	89.57	100.00	5.00	-
Standard Oil of Ind.	13.72	-	86.28	100.00	3.81	-
Standard Oil of N.J.	14.07	-	85.93	100.00	3.93	-
Phillips Petroleum Co.	16.61	-	83.39	100.00	4.09	-
Standard Oil of Ohio	11.88	5.08	83.04	100.00	3.71	3.75
Shell Oil Co.	16.90	-	83.10	100.00	4.37	-
Marathon Oil Co.	17.25	-	82.75	100.00	4.375	-
Pure Oil	18.32	-	81.68	100.00	3.85	-
Gen. Amer. Oil of Texas	19.10	-	80.90	100.00	4.75	-
Sunray DX Oil Co.	21.27	-	78.73	100.00	3.87	-
Signal Oil & Gas Co.	21.28	-	78.72	100.00	5.28	-
Superior Oil Co.	23.11	-	76.89	100.00	3.89	-
Continental Oil Co.	23.65	-	76.35	100.00	3.94	-
Union Oil of Calif.	24.30	-	75.70	100.00	4.05	-
Champlin Oil	24.78	2.12	73.10	100.00	4.50	3.00
Sinclair Oil Co.	27.45	-	72.55	100.00	3.97	-
Atlantic Richfield	24.49	4.20	71.31	100.00	3.98	3.75
Shamrock Oil & Gas Co.	35.60	-	64.40	100.00	4.37	-
Murphy Oil Co.	34.51	3.50	61.99	100.00	5.40	5.50
Kerr-McGee Oil Co.	38.34	-	61.66	100.00	5.16	-
Cities Service Oil Co.	38.91	1.37	59.72	100.00	4.08	4.40
Tidewater Oil Co.	35.27	8.82	55.91	100.00	4.14	4.80
Helmerich & Payne	47.67	-	52.33	100.00	4.95	-
Western Natural Gas Co.	42.94	18.62	38.44	100.00	5.56	5.00
Coastal States Gas Prod. Co.	75.12	-	24.88	100.00	5.59	-
Total	21.56%	1.35%	77.09%	100.00%	4.28%	4.19%

* Based on estimates where complete data was not available.

[6150]

[6151]

SCHEDULE 9

Producing Pipeline Companies' Capitalization
December 31, 1962 .

	Amounts in Thousands of Dollars			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Humble Gas Transmission Co.	-	-	20,744	20,744
Kentucky-West Virginia Gas Co.	500	-	25,051	25,551
United Natural Gas Co.	10,700	-	37,220	47,920
Cumberland & Allegheny	3,461	-	9,180	12,641
Kentucky Gas Transmission	4,691	-	9,057	13,748
Pennsylvania Gas Co.	12,475	-	20,960	33,435
Iroquois Gas Corp.	43,000	-	70,285	113,285
Cities Service Gas Co.	62,252	-	92,486	154,738
United Fuel Gas Co.	85,842	-	90,912	176,754
Consolidated Gas Supply Corp.	159,000	-	168,236	327,236
Ohio Fuel Gas Co.	145,109	-	150,353	295,462
Lone Star Gas Co.	164,075	1,347	166,802	332,224
Atlantic Seaboard Corp.	50,528	-	42,600	93,128
Manufacturers Light & Heat	73,774	-	61,023	134,797
Southern Natural Gas Co.	138,583	-	107,967	246,550
Alabama Tennessee Nat. Gas Co.	3,247	-	2,313	5,560
United Gas Pipe Line Co.	239,422	-	163,202	402,624
Kansas-Nebraska Nat. Gas Co.	22,329	8,825	20,399	51,553
Colorado Interstate Gas Co.	66,583	21,680	55,726	143,989
Nat. Gas Pipeline Co. of Amer.	239,859	40,000	131,948	411,807
Panhandle Eastern P.L. Co.	182,768	27,762	84,661	295,191
Mississippi River Trans. Corp.	5,566	-	2,167	7,733
Texas Gas Transmission Corp.	160,980	26,974	67,598	255,552
Tenneco	960,290	203,404	393,608	1,557,302
Trunkline Gas Co.	132,400	28,396	48,252	209,048
El Paso Natural Gas Co.	889,951	130,351	285,108	1,305,410
Texas Eastern Trans. Corp.	539,639	137,831	176,118	853,588
Combined Totals	$4,397,024	$626,570	$2,506,976	$7,530,570
Composite Ratios	58.39%	8.32%	33.29%	100.00%

SOURCE: F.P.C. Statistics of Natural Gas Pipeline Companies - 1962.

[6152]

SCHEDULE 10

Independent Producers' Capitalization
1962

	Amounts in Thousands of Dollars			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Amerada Petroleum Corp.	$ -	$ -	$ 211,271	$ 211,271
Midwest Oil Co.	-	-	54,652	54,652
Skelly Oil Co.	1,500	-	356,941	358,441
Sun Oil	16,027	-	694,511	710,538
Standard Oil of Calif.	186,100	20,341	2,678,707	2,885,148
Mobil Oil Co.	243,075	-	2,978,044	3,221,119
Gulf Oil Co.	298,047	-	3,416,650	3,714,697
Texaco Oil Co.	359,391	-	3,300,202	3,659,593
Aztec Oil & Gas Co.	3,525	-	30,280	33,805
Standard Oil of Ind.	390,574	-	2,455,434	2,846,008
Standard Oil of N.J.	1,298,853	-	7,935,177	9,234,030
Phillips Petroleum Co.	240,056	-	1,205,259	1,445,315
Standard Oil of Ohio	42,789	18,257	298,957	360,033
Shell Oil Co.	285,673	-	1,404,327	1,690,000
Marathon Oil Co.	95,067	-	455,969	551,036
Pure Oil	105,367	-	469,888	575,255
Gen. Amer. Oil of Texas	20,000	-	84,703	104,703
Sunray DX Oil Co.	105,761	-	391,520	497,281
Signal Oil & Gas Co.	58,644	-	216,963	275,607
Superior Oil Co.	65,095	-	216,531	281,626
Continental Oil Co	[illegible]	-	[illegible]	[illegible]
Union Oil of Calif.	170,169	-	530,002	700,171
Champlin Oil	29,167	2,500	86,026	117,693
Sinclair Oil Co.	[illegible]		957,095	1,319,262
Atlantic Richfield	205,159	35,200	597,348	837,707
Shamrock Oil & Gas Co.	43,805	-	79,230	123,035
Murphy Oil Co.	48,231	4,890	86,631	139,752
Kerr-McGee Oil Co.	69,704	-	112,120	181,824
Cities Service Oil Co.	505,831	17,837	776,498	1,300,166
Tidewater Oil Co.	303,682	75,937	481,481	861,100
Helmerich & Payne	10,802	-	11,860	22,662
Western Natural Gas Co.	26,671	11,565	23,876	62,112
Coastal States Gas Prod. Co.	72,299	-	23,948	96,247
Total	$5,901,364	$186,557	$33,390,751	$39,478,672
Weighted Average	14.94%	.48%	84.58%	100.00%

[6153]

SCHEDULE 11

Affiliated Producer Companies' Capitalization Ratios
December 31, 1962

	Percent of Total Capitalization			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Lone Star Producing	- %	- %	100.00%	100.00%
Union Producing Co.	19.63	-	80.37	100.00
Cities Service Oil Co.	25.56	-	74.44	100.00
Anadarko Production Co.	37.57	-	62.43	100.00
El Paso Products	37.31	.39	62.30	100.00
Colorado Oil & Gas Co.	27.16	18.50	54.34	100.00
P[illegible]n Oil Co.	54.74	-	45.26	100.00
Tenneco Oil Co.	60.22	-	39.78	100.00
Texas Gas Exploration	70.37	-	29.63	100.00
La Gloria Oil & Gas	73.26	-	26.74	100.00
Averages	40.58%	1.89%	57.53%	100.00%

SOURCE: Information supplied by the individual companies.

[6154]

PIPELINE PRODUCTION GROUP
Major Pipelines Not Included in Production Group
December 31, 1966

	Amounts in Thousands of Dollars				Percent of Total Capitalization			
	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization	Long-Term Debt	Preferred Stock	Common Equity	Total Capitalization
Algonquin Gas Trans. Co.	$ 55,360	$ -	$ 34,680	$ 90,040	61.48%	- %	38.52%	100.00%
Columbia Gulf Trans. Co.	125,230	-	111,468	236,698	52.91	-	47.09	100.00
Florida Gas Trans. Co.	120,955	-	68,365	189,320	63.89	-	36.11	100.00
Michigan Gas Storage Co.	13,200	-	19,483	32,683	40.39	-	59.61	100.00
Michigan Wisconsin P.L. Co.	273,602	-	107,929	381,531	71.71	-	28.29	100.00
Midwestern Gas Trans. Co.	48,600	10,000	25,430	84,030	57.84	11.90	30.26	100.00
Northern Natural Gas Co.	388,515	43,960	251,399	683,874	56.81	6.43	36.76	100.00
Pacific Gas Trans. Co.	83,301	-	28,671	111,972	74.39	-	25.61	100.00
South Texas Natural Gas Gathering Co.	11,234	-	9,397	20,631	54.45	-	45.53	100.00
Transcontinental Gas P.L. Corp.	470,697	85,564	160,851	717,112	65.64	11.93	22.43	100.00
Transwestern Pipeline Co.	155,270	-	55,563	210,833	73.65	-	26.35	100.00
East Texas Gathering Co.	1,217	505	833	2,555	47.63	19.77	32.60	100.00
	$1,747,181	$14[illegible],029	$874,069	$2 761,278	60.07%	4.17%	35.76%	100.00%
Weighted Averages	63.27%	[illegible].07%	31.65%	100.00%				

SOURCE: F.P.C. Statistics for Interstate Natural Gas Pipeline Companies - 1966

[6160]

DOCKET N
EXHIBIT 70
WITNESS:

PIPELINE PRODUCTION GROUP

Rebuttal Exhibit Showing Absence of Tax Spillover
for Pipeline Producers

Year 1962

[6161]

PIPELINE PRODUCTION GROUP

Rebuttal Exhibit Showing Absence of Tax Spillover for Pipeline Producers
Year 1962

Line No.		12% Return Per Permian Basin Opinion (1)	Net Tax Deductions (2)	Tax Base (3)
1	Colorado Interstate Gas Company	$ 1 640 848	$ 3 048 660	$(1 407 812)
2	El Paso Natural Gas Company	30 265 536	10 741 970	19 523 566
3	Humble Gas Transmission Company	886 562	918 949	(32 387)
4	Kansas-Nebraska Natural Gas Co., Inc.	894 915	549 242	345 673
5	Hope Natural Gas Company	4 273 751	3 600 059	673 692
6	Kentucky-West Virginia Gas Company	3 157 440	2 210 976	946 464
7	Natural Gas Pipeline Company of America	492 340	1 807 228	(1 314 888)
8	Panhandle Eastern Pipe Line Company	2 101 408	3 098 048	(996 640)
9	New York State Natural Gas Company	1 083 718	804 853	278 865
10	Southern Natural Gas Company	955 667	1 868 932	(913 265)
11	Tennessee Gas Pipeline Company	22 138 266	5 775 107	16 363 159
12	Texas Eastern Transmission Corporation	4 499 127	1 153 920	3 345 207
13	United Fuel Gas Company	4 991 212	2 409 754	2 581 458
14	Total	$77 380 790	$37 987 698	$39 393 092

[6162]

PIPELINE PRODUCTION GROUP

Rebuttal Exhibit Showing Absence of Tax Spillover for Pipeline Producers
Year 1962

Line No.		6-1/2% Return Per John Raymond Workpapers (1)	Net Tax Deductions (2)	Tax Base (3)
1	Colorado Interstate Gas Company	$ 888 793	$ 3 048 660	$(2 159 867)
2	El Paso Natural Gas Company	16 393 832	10 741 970	5 651 862
3	Humble Gas Transmission Company	480 221	918 949	(438 728)
4	Kansas-Nebraska Natural Gas Co., Inc.	484 746	549 242	(64 496)
5	Hope Natural Gas Company	2 314 949	3 600 059	(1 285 110)
6	Kentucky-West Virginia Gas Company	1 710 280	2 210 976	(500 696)
7	Natural Gas Pipeline Company of America	266 684	1 807 228	(1 540 544)
8	Panhandle Eastern Pipe Line Company	1 138 263	3 098 048	(1 959 785)
9	New York State Natural Gas Company	587 014	804 853	(217 839)
10	Southern Natural Gas Company	517 653	1 868 932	(1 351 279)
11	Tennessee Gas Pipeline Company	11 991 561	5 775 107	6 216 454
12	Texas Eastern Transmission Corporation	2 473 703	1 153 920	1 283 783
13	United Fuel Gas Company	2 703 573	2 409 754	293 819
14	Total	$41 915 272	$37 987 698	$ 3 927 574

Exhibit 71

PIPELINE PRODUCTION GROUP

Demonstration of Income Generated by a New Producing Property
at the Area Rate Proposed by Staff in Its Initial Brief of May 31, 1967

Line No.	Year	First (1)	Second (2)	Third (3)	Fourth (4)	Five thru Nineteen (5)	Twenty (6)	Twenty-one (7)	Twenty-two (8)	Total (9)	Cents Per Mcf (10)
1	Investment	$ 4 040 000	-	-	-	-	-	-	-	$ 4 040 000	4.04¢
2	Sales - Mcf	-	5 000 000	5 000 000	5 000 000	75 000 000	5 000 000	5 000 000	-	100 000 000	
	Revenues										
3	Gross Revenues	-	$823 000	$823 000	$823 000	$12 345 000	$823 000	$823 000	$ -	$16 460 000	16.46¢
4	Less: Royalty Interest		107 000	107 000	107 000	1 605 000	107 000	107 000	-	2 140 000	2.14
5	Net Working Interest Revenues		716 000	716 000	716 000	10 740 000	716 000	716 000	-	14 320 000	14.32
6	Add: Revenues from Liquids		192 000	192 000	192 000	2 880 000	192 000	192 000	-	3 840 000	3.84
7	Total Revenues	-	908 000	908 000	908 000	13 620 000	908 000	908 000	-	18 160 000	18.16
	Operating Revenue Deductions										
8	Production Operating Expenses	-	137 500	137 500	137 500	2 062 500	137 500	137 500	-	2 750 000	2.75
9	Production Taxes	-	57 500	57 500	57 500	862 500	57 500	57 500	-	1 150 000	1.15
10	Exploration & Development Costs	4 380 000	-	-	-	-	-	-	-	4 380 000	4.38
11	Regulatory Expense	-	7 000	7 000	7 000	105 000	7 000	7 000	-	140 000	.14
12	Depreciation and Depletion	-	118 000	118 000	118 000	1 770 000	118 000	118 000	-	2 360 000	2.36
13	Intangible Drilling Costs	1 680 000	-	-	-	-	-	-	-	1 680 000	1.68
14	Total Operating Revenue Deductions	6 060 000	320 000	320 000	320 000	4 800 000	320 000	320 000	-	12 460 000	12.46
15	Net Income Before Depletion	(6 060 000)	588 000	588 000	588 000	8 820 000	588 000	588 000	-	5 700 000	5.70
16	Depletion Allowance	-	249 700	249 700	249 700	3 745 500	249 700	249 700	-	4 994 000	4.99
17	Taxable Income	(6 060 000)	338 300	338 300	338 300	5 074 500	338 300	338 300	-	706 000	.71
18	F.I.T. @ 48%	(2 908 800)	162 400	162 400	162 400	2 435 800	162 400	162 400	-	339 000	.34
19	Net Income After Tax	$(3 151 200)	$425 600	$425 600	$425 600	$ 6 384 200	$425 600	$425 600	$ -	$ 5 361 000	5.36¢

[6165]

[7110]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Lee C. White, Chairman, L. J. O'Connor, Jr., Charles R. Ross, David S. Black, and Carl E. Bagge.

Hugoton-Anadarko Area Rate Proceeding	)	Docket No. AR64-1
Pipeline Production Area Rate Proceeding	)	Docket No. RP66-24

ORDER SEVERING PROCEEDINGS AND PRESCRIBING PROCEDURES

(Issued April 13, 1966)

The Commission, by order issued June 29, 1964, enlarged the issues in the Hugoton-Anadarko Area Rate Proceeding, Docket No. AR64-1, to provide that there be included in that proceeding "consideration of the extent to which, if any, the rates or cost allowances for pipeline gas production should be regulated on an area basis." On December 30, 1965, the Commission staff moved to sever the pipeline production question from this proceeding and for the institution of a separate proceeding to deal with the matter. Staff further moved that (1) a prehearing conference be held to delineate issues in evidence and (2) that all pipelines engaged in production be required to submit evidence and (3) that the examiner in the new proceeding consider the feasibility of a two-phase hearing respecting gas produced from dedicated reserves and that produced from future reserves.

On January 19, 1966, the Commission postponed all hearings and other procedure with respect to pipeline production pending action on the staff motion.

Staff's motion is supported by Texas Independent Producers and Royalty Owners Association (TIPRO), Municipal Gas Group (American Public Gas Association, the City of Chicago, the City of Denver, and the Memphis Gas And Water Division), the State of California and the California Public Utilities Commission (Cal PUC), and the Philadelphia Gas Works Division of The United Gas Improvement Company (PGW). PGW suggests that the matter be dealt within a rulemaking proceeding.

[7111]

Opposing the staff motion are two independent producers (Phillips and Humble), Union Producing Company, the Cities Service Group (classified as independent producers but affiliated with a pipeline company), two distributors (Michigan Gas Utilities Company and Central Illinois Light Company), and two groups of producing pipelines and their affiliates.[1] Most of the independent producers not represented by TIPRO take no position. A large percentage of the nation's producing pipelines are not parties to this proceeding or have taken no position.

Whether the Commission may or should depart from the cost-of-service method in fixing the price of pipeline produced gas is the precise issue to be determined in this investigation. The issue was originally consolidated with this proceeding for the principal reason that Hugoton-Anadarko is an area of considerable pipeline production and thus this proceeding provided an appropriate vehicle for evaluating the general pipeline production issue. For the reasons hereinafter stated we do not now believe that such a determination can be made within the context of the present proceeding.

[1] The Pipeline Production Group and the Pipeline Division of INGAA. A number of pipelines filed separate briefs in opposition to staff's motion. Most of the companies filing separate briefs, however, are also represented in the group briefs. Only the pipeline Division of INGAA, and not the entire membership, opposes staff motion.

[7111]

A group of pipelines asserting an interest in encouraging pipeline production activity have introduced considerable general evidence into the record detailing the reasons why they believe pipeline production is in the public interest and should be encouraged. The staff and some of the other parties have now introduced separate historical cost studies as of 1962 for pipeline production nationally and in the two regions involved in Docket Nos. AR64-1 and AR64-2 (taken from the all area questionnaire). However, no evidence has been introduced upon which a determination could be made of the impact upon the consumers of the various pipelines of substituting an area rate for one based upon each company's individual cost, nor has evidence been introduced which permits any meaningful judgment whether gas from leases or properties acquired by the pipelines during the formative period of the pipeline industry should be separately treated. Neither is there any evidence as to the relative acquisition costs over the years of pipelines which have engaged extensively in pipeline production as against those which have not.

[7112]

While the evidence introduced in the proceeding thus far is incomplete, it does appear to indicate that pipeline production in the Hugoton-Anadarko area is by no means typical of pipeline production throughout the nation. Our experience in pipeline rates cases would also indicate that much of the production in the area is of low cost, with the result that on a historic cost-of-service basis, it is significantly lower in cost than the nationwide cost of service for all gas. On the other hand, there is no evidence that nationwide all pipeline production, on a historical cost-of-service basis, has costs any lower than those of independent producers. Thus, there is no reason to believe that a determination with respect to the pipelines having production in the Hugoton-Anadarko area would or should necessarily be applicable to pipelines with production centered in other areas of the country. This situation is aggravated by the

fact that not all pipeline producers are parties to the proceeding and some of the major pipeline producers with no production in the Hugoton-Anadarko region have not participated to date.

In view of the present state of the record it appears probable that, if the pipeline production issues were left in the present proceeding, the Commission would be compelled to make its determination upon an inadequate record. The only other alternative would be to attempt at this late stage in the proceeding to remedy the present deficiencies in the record. This would inevitably delay substantially the final determination of proper area rates in *Hugoton-Anadarko* and *Texas Gulf Coast* areas to the clear detriment of both the producers and their jurisdictional customers.

It is regrettable that the pipeline production issue has been continued as part of this proceeding until such a late date. If the effect of staff's motion was merely to relieve it from the burden of proceeding we would deny the motion out of hand. We think, however, that this would be a disservice to all parties including those who oppose the motion. A principal basis for the opposition to the motion is that if the pipeline production issue is severed, much of the labor and expense of this proceeding will be wasted, especially that expended to putting in the evidence so far received. Examination of the evidence so far presented reveals that it consists principally of prepared questions and answers submitted for copying by the reporter. Such evidence may readily be received and considered in another proceeding. It should be supplemented rather than supplanted. Cross-examination has not yet been had. Under these circumstances little of the effort and expense will be wasted.

[7113]

Mere severance, however, is clearly not enough. The question remains whether there is any way in which reso-

lution of at least part of the pipeline production issue can be expedited in the light of the very real problems discussed above. We believe that there is. The essential question after all is whether future and additional pipeline production activities should be encouraged (or at least not penalized) and, if so, what is the most appropriate lawful pricing technique to achieve this objective. It is apparent that if putting pipeline production on an area price basis does not make sense for the future lease acquisitions, that it will make even less sense for the past acquired leases where we have high and low cost pipeline production depending upon combination of such factors as vintage and area of exploratory efforts. At the same time, it would appear that many of the most difficult evidentiary and policy problems can be avoided or at least deferred if, in any separate proceeding on pipeline production costing, consideration is initially limited to a determination of whether pipeline produced and self-consumed gas on leases acquired after the date of any final Commission policy determination—by rule or otherwise—should be priced on an area basis and, if so, the exact nature of such area rate.[2]

In severing this issue we hesitate to impose any rigid format on the interested parties at this time. Instead, we shall direct the hearing examiner in the separate proceeding to hold a prehearing conference which will expeditiously and firmly establish the specific issues which will be considered in the first phase of this proceeding which is denominated as follows:

> What is the most appropriate pricing method to be applied to natural gas utilized in a pipeline's interstate system which is produced by the pipeline or its affiliated producing company from leases acquired after the date of determination of this issue?

[2]Presumably, much if not all of the information already introduced by the pipeline production group and other parties who have directed themselves to this issue would be relevant to such a determination.

[7114]

Without in any way limiting the prerogatives of the Presiding Examiner to rule on the materiality and relevancy of the specific issues the parties may urge must be answered to resolve the foregoing question, we would suggest that the general areas of investigation, among others, should include evidence and data relating to: (1) the effect of pipeline production area rates on various aspects of individual pipeline rate determinations, such as but not limited to, rate of return and income tax allowance (2) the impact on the independent producer segment of the natural gas industry, if pipeline production is to be encouraged; (3) the claimed advantages and benefits to the pipeline and the consumers from pipeline production as reflected in the past operations of producing pipelines and as compared with the operations of pipelines not engaged in production activities.

Clearly, the formulation of a meaningful record which will provide as broad a base as possible for resolving the overall issue set out above, requires participation of all pipeline companies engaged in the production of natural gas in more than an incidental capacity and of a substantial segment of other pipeline companies whose rates and charges are subject to the jurisdiction of the Commission. Accordingly, each of the pipeline companies listed in Appendix A attached hereto are made respondents in this severed proceeding.

Attention is directed to the Commission's views with respect to the use of the conference technique and the ultimate objective of expediting the Commission's hearing proceedings as set forth in Order No. 217. Each of the respondents shall, at the prehearing conference, set forth on the record a statement summarizing the extent to which it proposes to participate in the first phase of this proceeding (as set out above), the specific issues relating thereto which it deems relevant and material, the nature of the evidence it proposes to present on such issues, and any other matters germane and relevant to this phase of the proceed-

ing which will aid the determination thereof. The requirements of the aforementioned statement shall also be applicable to Commission staff and any other party permitted to participate as a respondent or intervener in this proceeding. It is also our intent that the parties, at the prehearing conference herein provided, shall stipulate, to the maximum feasible extent, on all issues of fact not in dispute, items to be officially noticed, relevant material which may profitably be incorporated into the record of this severed proceeding either from the responses to the All Areas Questionnaire and evidence introduced in AR64-1 and other proceedings.

[7115]

The Examiner is requested to exercise to the full his powers to expedite these proceedings and to provide a full and complete record by requiring service of the facts relating to each specific issue he determines material and relevant by the party or parties in control of the facts relating to that issue upon all other parties to this proceeding.

Certain of the parties have requested oral argument on Staff's motion. It is our view that oral argument is not necessary or appropriate since the actions herein relate to procedural matters, and grant of such request could only result in further delay. Moreover, the views of the several parties are fully set forth in the briefs submitted. Accordingly, the requests for oral argument are hereby denied.

The Commission orders:

(A) The proceedings promulgated by our "Order Enlarging Issues" issued June 29, 1964, concerning the methods to be used in pricing pipeline produced gas which were consolidated for hearing and decision with the Hugoton-Anadarko Area Rate Proceeding, Docket No. AR64-1 *et al.*, are hereby severed from that docket.

(B) A separate proceeding entitled "Pipeline Production Area Rate Proceeding, Docket No. RP66-24, is hereby in-

stituted, pursuant to Sections 4, 5, 10, 14, 15 and 16 of the Natural Gas Act, to determine the proper method to be used by the Commission in pricing natural gas produced by pipelines and or acquired by them from their affiliated producers.

(C) A prehearing conference shall be held in a hearing room of the Commission at 441 G Street, N.W. Washington, D. C. commencing 10 a.m. May 17, 1966 before Presiding Examiner Allan C. Lande in the proceeding instituted by paragraph (B) above, limited to the first phase of this proceeding as denominated in the text of this order, and to achieve the purposes set forth in the text of this order.

(D) Each of the pipeline companies listed in Appendix A attached hereto are joined as parties-respondent in the proceeding instituted by paragraph (B) above.

(E) At the conclusion of the prehearing conference prescribed by paragraph (C) above, or shortly thereafter as he deemed necessary, the Presiding Examiner shall set forth on the record or by separate order his determination of the specific issues material and relevant to the first phase of this proceeding on which evidence is to be adduced on the record and shall designate, if necessary, the party or parties which are in control of the facts relating to any such specific and set the date on which such facts shall be furnished to each party to the proceeding.

[7116]

(F) Concurrently with the actions taken under paragraph (E) above, the Presiding Examiner shall also set the dates for service of testimony and exhibits by the parties and the date for commencement of the hearing and cross-examination.

(G) Nothing herein shall be deemed to limit the authority of the Presiding Examiner's control of these proceedings to modify or enlarge on the procedures here provided consonant with our underlying and expressed purpose to

adduce a full and complete record on the first phase of this proceeding as expeditiously as possible.

(H) Any interested person, other than the respondents specifically listed in Appendix A, who desires to participate as an intervener in the proceeding here instituted shall, on or before May 2, 1966, file a notice of intervention or petition to intervene in accordance with Section 1.8 of the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Bagge concurring filed a separate statement appended hereto.

(S E A L)

Joseph H. Gutride,
Secretary.

[7117]

APPENDIX "A"

PIPELINE PRODUCTION AREA RATE PROCEEDING
DOCKET NO. RP66-24

PIPELINE COMPANIES JOINED AS
PARTIES-RESPONDENT

Alabama Tennessee Natural Gas Company
Algonquin Gas Transmission Company
Atlantic Seaboard Corporation
Cities Service Gas Company
Colorado Interstate Gas Company
Consolidated Gas Supply Corporation
Cumberland and Allegheny Gas Company
El Paso Natural Gas Company
Florida Gas Transmission Corporation
Humble Gas Transmission Company
Kansas-Nebraska Natural Gas Company Inc.
Kentucky Gas Transmission Corporation
Kentucky-West Virginia Gas Company

Lone Star Gas Company
Lone Star Gathering Company
Manufacturers Light and Heat Company, The
Michigan Wisconsin Pipe Line Company
Midwestern Gas Transmission Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
Northern Natural Gas Company
Ohio Fuel Gas Company, The
Oklahoma Natural Gas Gathering Corporation
Pacific Gas Transmission Company
Panhandle Eastern Pipe Line Company
Southern Natural Gas Company
South Texas Natural Gas Gathering Company
Tennessee Gas Transmission Company
Tennessee Natural Gas Lines, Inc.
Texas Eastern Transmission Corporation
Texas Gas Pipe Line Corporation
Texas Gas Transmission Corporation
Transcontinental Gas Pipe Line Corporation
Transwestern Pipeline Company
Trunkline Gas Company
United Fuel Gas Company
United Gas Pipe Line Company

[7118]

Hugoton-Anadarko	)	
Area Rate Proceeding	)	Docket No. AR64-1
Pipeline Production	)	
Area Rate Proceeding	)	Docket No. RP66-24
	)	

BAGGE, Commissioner, *concurring:*

I must join my colleagues in ordering the pipeline production issue severed from this proceeding since I, like they, believe that such a severance will enable both the Hugoton-Anadarko Area Rate Proceeding and the Pipeline

Production Area Rate Proceeding to be decided more expeditiously than they could be if left in the same proceeding. However, I cannot join them without expressing my reluctance to do so.

It is embarrasing to be placed in a situation where we must grant a motion which is procedurally abhorrent in order to attain an objective which is substantively necessary.

That this motion was filed some eighteen months after the Commission ordered the issues combined and that it was filed after many parties had expended considerable time, money and effort preparing testimony in accordance with that order does not obviate the substantive necessity for severance.

So, although I fear that this will be misinterpreted as a high-handed and collusive action taken by the Commission and our staff in derogation of the rights of those most immediately affected, I must, with great misgivings, join in today's decision.

/s/ Carl E. Bagge, Commissioner

[7510]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Charles R. Ross, David S. Black, and Carl E. Bagge.

Pipeline Production Area) Rate Proceeding)	Docket No. RP66-24

ORDER PERMITTING AND DENYING INTERVENTIONS

(Issued May 25, 1966)

Pursuant to the Commission's order issued April 13, 1966, instituting the "Pipeline Production Area Rate Proceeding, Docket No. RP66-24," timely petitions and notices to intervene were filed by the persons named in the following intervener categories:

I. The following state commissions filed notices of intervention under Section 1.8 of our Rules of Practice and Procedure:

Iowa State Commerce Commission (April 29, 1966).
Michigan Public Service Commission (May 3, 1966).
Mississippi Public Service Commission (April 25, 1966).
Public Service Commission of the State of New York (April 27, 1966).
Public Service Commission of Wisconsin (April 28, 1966).
State Corporation Commission of the State of Kansas (April 27, 1966).
The People of the State of California and the Public Utilities Commission of the State of California (May 2, 1966).
The Public Utilities Commission of Ohio (May 2, 1966).

[7510]

II. State, county, and municipal governmental bodies filing petitions to intervene:

State of Wisconsin (May 2, 1966).
City of Chicago (April 28, 1966).
City and County of Denver, Colorado (May 2, 1966).
City of Los Angeles (April 29, 1966).
City and County of San Francisco (May 2, 1966).
City Group Gas Defense Association consisting of the Kansas Cities of Altamont, Atchison, Chanute, Countryside, Erie, Fairway, Girard, Grenola, Howard, Iola, Leavenworth, Neodesha, and Prairie Village, and the Missouri Cities of Aurora, Carl Junction, Carthage, Independence, Joplin, Kansas City, Marshall, Monett, Mt. Vernon, Neosho, Nevada, Oronogo, St. Joseph, Springfield, Waverly, and Webb City (May 2, 1966).

[7511]

III. Natural gas distribution companies, natural gas distribution company associations, natural gas producers and association of natural gas producers filing petitions to intervene:

Atlanta Gas Light Company (May 2, 1966).
American Public Gas Association consisting of gas distributors within the States of Alabama, Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Nebraska, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia and Washington (May 2, 1966).
The Berkshire Gas Company (May 2, 1966).
Boston Gas Company
The Bridgeport Gas Company
Bristol and Warren Gas Company
Brockton Taunton Gas Company
Buzzards Bay Gas Company
Cambridge Gas Company

Central Massachusetts Gas Company
Concord Natural Gas Corporation
The Connecticut Gas Company
Fall River Gas Company
Fitchburg Gas and Electric Light Company
Gas Service, Inc.
The Greenwich Gas Company
The Hartford Electric Light Company
Haverhill Gas Company
City of Holyoke, Massachusetts Gas and Electric Department
Lawrence Gas Company
Lowell Gas Company
Lynn Gas Company
Manchester Gas Company
Mystic Valley Gas Company
New Bedford Gas and Edison Light Company
The New Britain Gas Light Company
New Haven Gas Company
The Newport Gas Light Company
North Attleboro Gas Company
Northampton Gas Light Company
North Shore Gas Company
City of Norwich, Department of Public Utilities
Norwood Gas Company
The Pequot Gas Company
Providence Gas Company
South County Gas Company
Hartford Gas Company

Springfield Gas Light Company
Tiverton Gas Company
Valley Gas Company
Wachusett Gas Company
City of Westfield Gas and Electric Light Department
Worcester Gas Light Company

The Brooklyn Union Gas Company (April 29, 1966).

Central Hudson Gas & Electric Corporation (May 2, 1966).

Central Illinois Light Company (May 2, 1966).
Central Illinois Public Service Company (May 2, 1966).
Consolidated Edison Company of New York, Inc. (April 29, 1966).
Gulf Oil Corporation (May 2, 1966).
Amerada Petroleum Corporation
The Atlantic Refining Company
Continental Oil Company
Kerr-McGee Corporation
Marathon Oil Company
Pan American Petroleum Corporation
Phillips Petroleum Company
Shell Oil Company
Sinclair Oil & Gas Company
Skelly Oil Company
Warren Petroleum Corporation
Humble Oil & Refining Company (May 2, 1966).
Hunt Oil Company (May 5, 1966).
Illinois Power Company (May 2, 1966).
Iowa Electric Light and Power Company (May 2, 1966).
Iowa Public Service Company (May 2, 1966).
Long Island Lighting Company (April 27, 1966).
Memphis Light, Gas and Water Division (May 2, 1966).
Metropolitan Utilities District of Omaha (May 2, 1966).
Michigan Gas Utilities Company (April 26, 1966).
Minnesota Natural Gas Company (April 28, 1966).
Mississippi Valley Gas Company (April 29, 1966).
Niagara Mohawk Power Corporation (April 29, 1966).
Northern Illinois Gas Company (May 2, 1966).
Northern Natural Gas Producing Company (May 2, 1966).
Orange and Rockland Utilities, Inc. (May 2, 1966).
Pacific Gas and Electric Company (May 2, 1966).
Pacific Lighting Service and Supply Company, Southern California Gas Company, and Southern Counties Gas Company of California (May 2, 1966).

Philadelphia Electric Company (May 2, 1966).
Philadelphia Gas Works Division of the United Gas Improvement Company (April 28, 1966).
Public Service Company of Colorado (May 4, 1966).
Public Service Electric and Gas Company (April 25, 1966).
San Diego Gas & Electric Company (April 29, 1966).

[7513]

Socony Mobile Oil Company, Inc. (May 2, 1966).
Sun Oil Company (May 2, 1966).
Superior Oil Company (May 2, 1966).
Wisconsin Gas Company (May 2, 1966).
Texas Independent Producers & Royalty Owners Association (April 27, 1966).
Texaco, Inc. (May 2, 1966).
Washington Gas Light Company (May 2, 1966).
Willmut Gas and Oil Company (May 2, 1966).

In addition, The Pipeline Division, Independent Natural Gas Association of America (INGAA), a recognized trade organization which includes representatives of most of the large natural gas transmission companies subject to the Commission's jurisdiction, has filed a petition to intervene. Since INGAA's Pipeline Division participation will be that of an industry trade association, we shall grant intervention while recognizing that many of the Pipeline Division members are presently respondents to the proceeding.

IV. Cities Service Oil Company (Oil Company) and Columbian Fuel Corporation (Columbian), Union Producing Company (Union), and The Preston Oil Company (Preston Oil) have timely filed petitions to intervene.

In our order of April 13, we held that the first phase of the Pipeline Production Area Rate Proceeding should cover the matter of "what is the most appropriate pricing method to be applied to natural gas * * * which is produced by the pipeline or its *affiliated producing company* * * *?" (emphasis added). Accordingly, in our order issued today des-

[7513]

ignating additional respondents to the proceeding in Docket No. RP66-24, we have amended Appendix A to the Commission's order of April 13, to include as additional respondents to this proceeding, *inter alia*, the following affiliated producing companies: Oil Company, Columbian, Union and Preston Oil.

Additionally, a group of pipeline companies (including one producer company, Preston Oil) referred to as the Pipeline Production Group[1] has filed a petition to intervene. Each of the member companies of that Group

[1] Cities Service Gas Company, Colorado Interstate Gas Company, Columbia Gas System Service Corporation (United Fuel Gas Company, Inc., and the Preston Oil Company), Kansas-Nebraska Natural Gas Company, Inc., Lone Star Gas Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipe Line Corporation, Trunkline Gas Company and United Gas Pipe Line Company.

[7514]

was individually named as a respondent (except Preston Oil which is being included as a respondent in the aforementioned separate order issued today) in our order issued April 13, instituting this proceeding. Since each of the above petitioners is now specifically named as a respondent herein, entitled to all of the rights of a party to this proceeding and including the requested "right to file pleadings, introduce evidence, cross-examine witnesses", it is not necessary or appropriate that they be permitted to intervene either individually or as a group. Accordingly the petition of the so-called Pipeline Production Group should be denied. However, consistent with our desire to expedite this proceeding, the denial of the Pipeline Production Group's petition to intervene is not intended to preclude grouping of parties having a common interest. Accordingly, where appropriate to do so and without derogation of the rights

of any parties, parties having common interests should be grouped, thereby limiting the number of persons individually and actively participating in this proceeding.

The Commission orders:

(A) Subject to the rules and regulations of the Commission, all the petitioners and state commissions named in paragraph II and III are permitted to intervene in this proceeding and to participate on a joint or individual basis. *Provided, however,* That the participation of such interveners shall be limited to matters affecting asserted rights and interests specifically set forth by said petitioners in their petitions and *Provided, further,* That the admission of said petitioners as interveners shall not be construed as recognition by the Commission that they might be aggrieved because of any order or orders of the Commission entered in this proceeding.

(B) The petitions for leave to intervene filed in these consolidated proceedings by the petitioners named in Paragraph IV above are hereby denied.

By the Commission.

(S E A L)

Joseph H. Gutride,
Secretary.

* * *

[7860]

The injection of such a new procedural issue into the matter would seriously cloud any Commission decision and give rise to extensive judicial review on this question alone. See *e.g.* Petition by Solicitor General for Writ of Certiorari in No. 463, 1966 Term, *Udall v. FPC* et al.[3] Should the courts deem that an evidentiary record is required, as seems reasonably probably based on existing precedent, then all of the time spent in the so-called "rulemaking" proceeding[4] would be wasted and the parties required to return to the present posture of the proceeding. Thus, the Pipeline Production Group's proposed new proceeding would lead to confusion and probable extended delay which clearly are not in the public interest.

3. There is no showing that continuation of the present proceeding under the Commission's Order of April 13, 1966 will adversely affect either the industry or the consuming public.

---

[3] The questions alleged to be presented by the Solicitor General are as follows:

> Questions presented: (1) Can Federal Power Commission issue license for hydroelectric project without conducting its own fact investigation to develop full record on desirability of federal development? (2) Did Secretary of Interior's failure to make timely application for leave to present evidence in support of federal development excuse commission from such inquiry? (35 U.S. L. Week, 3107.)

[4] It is by no means clear that the present proceeding is not in the nature of rulemaking. The key point is not the label of the proceeding but whether evidence is required. The Commission has properly ruled that a complete factual investigation is necessitated for resolution of the complex issues before it.

[10045]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Pipeline Production
Area Rate Proceeding — Docket No. RP66-24

PRESIDING EXAMINER'S INITIAL DECISION ON RATES FOR NEW GAS PRODUCED BY PIPELINES AND PIPELINE AFFILIATES (PHASE I)

(Issued March 3, 1969)

TABLE OF CONTENTS

[10047]

[10048]

APPEARANCES

Charles E. McGee and *John T. Ketcham* for Algonquin Gas Transmission Company

D. Pierre G. Cameron, Jr. for Kentucky Gas Transmission Company, United Fuel Gas Company, Manufacturers Light and Heat Company, The Preston Oil Company, Ohio Fuel Gas Company, Atlantic Seaboard Corporation and Cumberland and Allegheny Gas Company

Charles V. Wheeler and *Daniel R. Hopkins* for Cities Service Gas Company

C. C. Cammack, R. J. Leithead and *Graydon D. Luthey* for Cities Service Oil Company and Columbian Fuel Corporation

James L. White, Raymond N. Shibley and *William Warfield Ross* for Colorado Interstate Gas Company

James L. White for Colorado Oil and Gas Company

Thomas A. White, Lawrence L. Gray, Norman A. Flaningam, Charles R. Brown, Kenneth M. Waters and *H. B. Griffith* for Consolidated Gas Supply Corporation

G. Scott Cuming, Charles V. Shannon, David T. Burleson, C. Frank Reifsnyder and *Stanley S. Harris* for El Paso Natural Gas Company

Carl Illig, Jesse H. Foster, Jr., Martin N. Erck, James K. Scholler and *Robert L. Norris* for Humble Gas Transmission Company and Humble Oil & Refining Company.

Donald I. Moritz and *John T. Brown* for Kentucky-West Virginia Gas Company

Manuel J. Edling, Jr., Richard B. Williams, John W. Scott and *Louis L. Da Pra* for Lone Star Gas Company and Lone Star Gathering Company

Raymond N. Shibley and *William Warfield Ross* for Lone Star Gas Company

[10049]

Charles V. Shannon, Louis Flax and *Paul S. Davis* for Michigan Wisconsin Pipe Line Company

W. C. Braden, Jr., and *L. R. Pankonien* for Midwestern Gas Transmission Company

William W. Bedwell and *James H. Wuller* for Mississippi River Transmission Corporation

Charles McDugald, William Brackett, Paul Goldstein, Raymond Petersen, Raymond N. Shibley and *William Warfield Ross* for Natural Gas Pipeline Company of America

F. Vinson Roach, Jack C. Osborne, Walter E. Gallagher, Frank J. Duffy, Raymond N. Shibley and *William Warfield Ross* for Northern Natural Gas Company

John L. Arrington, Jr. for Oklahoma Natural Gas Gathering Corporation

Richard H. Peterson, Malcolm H. Furbush, John A. Sproul and *John S. Cooper* for Pacific Gas Transmission Company

William J. LeBuhn, Raymond N. Shibley and *William Warfield Ross* for Panhandle Eastern Pipe Line Company

Hugh J. Morgan, Jr., William S. Tarver, Lewis Carroll, Peter G. Smith, Raymond N. Shibley and *William Warfield Ross* for Southern Natural Gas Company

Sherman S. Poland, Clinton B. Fascett and *Bradford Ross* for South Texas Natural Gas Gathering Company

D. Pierre G. Cameron, Jr. and *Donald M. Ochacher* for The Preston Oil Company

Joseph F. Weiler, Jack D. Head and *Keith M. Pyburn* for La Gloria Oil and Gas Company

Barclay D. McMillen, John H. Watson and *Robert E. Shaw* for Tenneco Oil Company

[10050]

Harry S. Littman, Jack Werner, W. C. Braden, Jr., Roy Alletag, Robert E. Shaw, Richard Littrell, Harold Talisman and *Melvin Richter* for Tennessee Gas Pipeline Company a Division of Tenneco, Inc.

Jack D. Head, Joseph F. Weiler and *Keith M. Pyburn* for Texas Eastern Transmission Corporation

Justin R. Wolf, Stanley Wanger and *Elliott G. Flowers* for Texas Gas Pipe Line Corporation

Christopher T. Boland, George J. Meiburger, Robert O. Koch, Raymond N. Shibley and *William Warfield Ross* for Texas Gas Transmission Corporation

William H. Davidson, Jr., Thomas F. Ryan, Ray V. Loftin, Jr., Raymond N. Shibley and *William Warfield Ross* for Transcontinental Gas Pipe Line Corporation

James W. McCartney for Transwestern Pipeline Company

Leland F. Cadenhead, Raymond N. Shibley and *William Warfield Ross* for Trunkline Gas Company

Saunders Gregg, W. O. Crain, Thomas Fletcher, and *J. C. Ohrt* for Union Producing Company

D. Pierre G. Cameron, Jr., Raymond N. Shibley and *William Warfield Ross* for United Fuel Gas Company

Raymond N. Shibley, William Warfield Ross and *Saunders Gregg* for United Gas Pipe Line Company

Edwin S. Nail for Amerada Petroleum Corporation

Charles F. Wheatley, Jr., Mathias M. Mattern, Leonard Campbell, Max Zall and *Reuben Goldberg* for American Public Gas Association consisting of gas distributors within the States of Alabama, Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Nebraska, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia and Washington; and also for the City of

Chicago, the City and County of Denver, and Memphis Light, Gas and Water Division

[10051]

Stuart J. Scott and *Bernard A. Foster, Jr.* for the Atlantic Richfield Company

John W. Glendening, Jr. and *John S. Schmid* for the New England Intervenors comprising: The Berkshire Gas Company, Boston Gas Company, The Bridgeport Gas Company, Bristol and Warren Gas Company, Brockton Taunton Gas Company, Buzzards Bay Gas Company, Cambridge Gas Company, Central Massachusetts Gas Company, Concord Natural Gas Corporation, The Connecticut Gas Company, Fall River Gas Company, Fitchburg Gas and Electric Light Company, Gas Service, Inc., The Greenwich Gas Company, The Hartford Electric Light Company, Haverhill Gas Company, City of Holyoke, Massachusetts Gas and Electric Department, Lawrence Gas Company, Lowell Gas Company, Lynn Gas Company, Manchester Gas Company, Mystic Valley Gas Company, New Bedford Gas and Edison Light Company, The New Britain Gas Light Company, New Haven Gas Company, The Newport Gas Light Company, North Attleboro Gas Company, Northhampton Gas Light Company, North Shore Gas Company, City of Norwich, Department of Public Utilities, Norwood Gas Company, The Pequot Gas Company, Providence Gas Company, South County Gas Company, Hartford Gas Company, Springfield Gas Light Company, Tiverton Gas Company, Valley Gas Company, Wachusett Gas Company, City of Westfield Gas and Electric Light Department, Worcester Gas Light Company

Edward F. Russell, Harry G. Hill Jr. and *Barbara M. Suchow* for The Brooklyn Union Gas Company

Mary Moran Pajalich, J. Calvin Simpson, Sheldon Rosenthal and *Lawrence Q. Garcia* for The People of the State of California and the Public Utilities Commission of the State of California

[10051]

Walter A. Bossert, Jr., Morrell S. Lockhart and *Theodore J. Carlson* for Central Hudson Gas & Electric Corporation

Charles V. O'Hern, Jr., for Central Illinois Light Company

Martin Hogan, Raymond F. Simon, Mathias M. Mattern, Charles F. Wheatley, Jr., Leonard Campbell, Max Zall and *Reuben Goldberg* for City of Chicago

Robert Lee Kessler for Public Utilities Commission of the State of Colorado, and The State of Colorado, *ex rel.*

[10052]

James O. Malley, Jr., H. G. Skinner and *Ronald E. Jones* for Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation and Orange and Rockland Utilities, Inc.

Bruce R. Merrill, Joseph C. Johnson and *Tom Burton* for Continental Oil Company

Warren M. Sparks and *Donald R. Arnett* for Gulf Oil Corporation, Kerr-McGee Corporation and Warren Petroleum Corporation

Robert W. Henderson and *Donald K. Young* for Hunt Oil Company

Robert S. Hunt and *Peter B. Fazio, Jr.* for Illinois Power Company

Harry L. Albrecht for Independent Natural Gas Association of America, The Pipeline Division

Jack F. Kenney for Iowa Public Service Company

Robert W. Russell and *Roger Arnebergh* for City of Los Angeles

Donald M. Ochacher for Columbia Gas Systems Service Corporation

Edward M. Barrett, Bertram D. Moll and *Morton L. Simons* for Long Island Lighting Company

Jack Fariss for Marathon Oil Company

George C. Pardee for Metropolitan Utilities District of Omaha

Richard M. Merriman for Michigan Gas Utilities Company

T. P. Hamill, R. D. Haworth, J. T. McMahon, and *Charles S. Chester* for Mobil Oil Corporation and Northern Natural Gas Producing Company

John W. Scott and *Louis L. Da Pra* for Minnesota Natural Gas Company

Payton G. Bowman, III for Mississippi Valley Gas Company

Frederick T. Searls, Malcolm H. Furbush, Stanley T. Skinner, John S. Cooper and *Sanford M. Skaggs* for Pacific Gas and Electric Company

[10053]

K. R. Edsall, H. L. Goth, Robert Salter and *William H. Owens* for Pacific Lighting Service and Supply Company, Southern California Gas Company, and Southern Counties Gas Company of California

J. P. Hammond, T. C. McCorkle and *William H. Henderson* for Pan American Petroleum Corporation

Robert W. Maris, William T. Coleman, Jr. and *Thomas K. Gilhool* for Philadelphia Gas Works Division of the United Gas Improvement Company

Kenneth Heady and *John R. Rebman* for Phillips Petroleum Company

E. A. Stansfield for Public Service Company of Colorado

J. Harry Mulhern, Edward S. Kirby and *James R. Lacey* for Public Service Electric and Gas Company

Sherman Chickering, C. Hayden Ames, Stanley Jewel and *Donald J. Richardson, Jr.* for San Diego Gas & Electric Company

Robert R. Laughead and *Thomas N. O'Connor* for City and County of San Francisco

[10053]

Oliver L. Stone and *Thomas G. Johnson* for Shell Oil Company

Paul Davis and *Charles E. McGee* for Sinclair Oil & Gas Company

Richard J. Dent for Skelly Oil Company

Phillip D. Endom for Sun Oil Company

William T. Kilbourne, Herbert W. Varner and *Homer J. Penn* for Superior Oil Company

William K. Tell, Jr. and *William R. Slye* for Texaco Inc.

John Davenport for Texas Independent Producers & Royalty Owners Association

William E. Torkelson and *Clarence B. Sorensen* for Public Service Commission of Wisconsin

Robert B. McConnell and *Bronson C. LaFollette* for State of Wisconsin

[10054]

Richard M. DiValerio and *W. J. Scott* for United Natural Gas Company, Pennsylvania Gas Company, Iroquois Gas Corporation and Sylvania Corporation

Louis R. Reif for National Fuel Gas Company and Iroquois Gas Corporation

Raymond N. Shibley and *William Warfield Ross* for Kansas-Nebraska Natural Gas Company, Inc.

Arnold D. Berkeley, Harry Gollomp, Kenneth H. Plumb, Lloyd E. Dietrich, Robert A. Jablon, A. Michael Cappalletti and *Robert J. Andrade* for the Staff of the Federal Power Commission

[10055]

I. INTRODUCTION

LANDE, PRESIDING EXAMINER: The purpose of Phase I of these proceedings is to determine whether it is necessary

to make a change in the Commission's present regulatory practice in pricing gas obtained by pipelines through their own or affiliated production from reserves which may be acquired in the near future through discovery or purchase of leases. The instant proceedings were initiated by Commission Order issued April 13, 1966, (35 FPC 497) to determine ". . . What is the most appropriate pricing method to be applied to natural gas utilized in a pipeline's interstate system which is produced by the pipeline or its affiliated producing company from leases acquired after the date of determination of this issue?" The second phase of these proceedings is to deal with possible changes in the pricing method in effect during the past period. In its order of April 13, 1966, the Commission also raised the specific underlying issue: "Whether the Commission may or should depart from the cost-of-service method in fixing the price of pipeline produced gas is the precise issue to be determined in this investigation."

Up to now, prices for jurisdictional gas produced by pipelines and pipeline affiliates were being fixed by the Commission under the cost-of-service method, with minor variations. However, by far the greater part of jurisdictional gas is produced by independent producers, who are or soon will be subject to area rate pricing. A brief description of these two methods follows.

A. *Cost-Of-Service Method*

The Commission has traditionally followed cost-of-service regulations in treating pipeline and pipeline affiliate produced gas for rate-making purposes. Under this method, the natural gas in place and the properties and equipment utilized in producing it are included in the rate base, along with the transmission, compression, and other facilities employed in transporting and selling it to the customers, at the net investment which they represent, *i.e.*, their original cost less the reserves which have been accrued to cover their depletion and depreciation. In addition to a return thereon equal to the rate of return found reasonable for the pipe-

[10055]

line operation overall, there are included in the recoverable costs of service,

[10056]

upon which the charges to jurisdictional customers are based, all operating expenses chargeable to production, including such uncapitalized exploratory and development outlays as delay rentals, geological surveys, and the expenses of drilling dry holes. Thus all of the costs and risks incurred in the search for gas by a pipeline are shifted from the stockholders to the customers of the pipeline. In addition, all expenses associated with the extraction of liquid hydrocarbons, such as natural gasoline, are also included among the allowable operating expenses, but corresponding production credits are made of the revenues from the sale of such products. Under the rate-base approach allowances for taxes on the production property are made in accordance with the actual payments made,[1] thus transferring to the rate-payer all the savings of federal income taxes permitted by statute to be enjoyed by gas producers through the allowances made for depletion[2] and intangible well-drilling expense[3] (*Panhandle Eastern Pipe Line Company, et al.* 13 FPC 53 at 60 and 61).

B. *Area Rate Method*

Area rates have recently been fixed by the Commission on the basis of average current production costs as well as historic costs. Special provisions were made for small producers; for any producer who felt the ceilings were grossly unfair for it; and for substandard gas.

[1] Section 203(e) of the Revenue Act of 1964, has eliminated any authority on the part of the Commission to use the investment tax credit without the consent of the taxpayer to reduce the federal income taxes of natural gas pipelines in establishing their cost-of-service. These companies are free to retain the tax savings desired from the investment tax credit and use them in any proper manner decided upon by company management.

[2] Revenue Act of 1926; Internal Revenue Code, Secs. 23(a) and 114(b) (3) and (4).

[3] Treasury Department, Regulations III, Sec. 29.33 (M)-16.

[10057]

On May 1, 1968, the Supreme Court upheld the Commission's landmark decision fixing maximum prices for natural gas produced in the Permian Basin area, *Permian Basin Area Rate Cases* 390 U. S. 747 (1968). Gas producers in the Permian Basin, which covers west Texas and southeast New Mexico and involves over 40% of jurisdictional sales by independent producers in the Continental United States, will be hereafter processed at an area rate. Another 50% of jurisdictional sales in other areas are covered by now pending area rate cases. The principal Permian producers directly affected are Phillips Petroleum Co.; Continental Oil Co.; Humble Oil & Refining Co.; Gulf Oil Corp., and Texaco Inc. The pipeline companies that are directly concerned are El Paso Natural Gas Co., which buys 73% of Permian gas sold in interstate commerce; Northern Natural Gas Co., which buys 18%, and Transwestern Pipeline Co., which takes 9%. The first proceeding to fix Permian-area rates started in 1961 and was concluded in 1965. The rates that the FPC fixed, for current gas from existing wells and that the Supreme Court approved, were at ceiling prices of 14.5 cents per 1,000 cubic feet of gas for Texas producers and 13.5 cents for New Mexico producers. To stimulate exploration for new gas sources, the FPC set somewhat higher ceilings for gas produced after January 1, 1961.

The Supreme Court's opinion explored in detail and upheld each aspect of the FPC decision. The court said that Permian producers' prices had gone up steadily, reflecting in part "the inability or unwillingness of pipelines to bargain vigorously for reduced prices." Consequently, it said, *"the consumer is obliged to rely upon the commission to provide effective protection from excessive rates."* (Emphasis supplied)

C. *Initial Positions*

During the prehearing conferences, the parties made statements of position concerning the proper applicability of the

[10057]

prevailing rate regulations, the need for new regulations, and the breakdown of the pertinent issues. Most respondents urged that the issues should be broadly defined. They maintained that the evidence which each party proposed to adduce would define the issues. Staff Counsel, the State of California and its Public Utilities Commission (California), the American Public Gas Association, City of Chicago, City and County of Denver, and Memphis Light, Gas and Water Division (Municipal Group) as well as El Paso Natural Gas Company (El Paso) favored specific and detailed statements of issues. When it became apparent that a meeting of the minds of the parties with respect to issues in

[10058]

this proceeding could not be reached, the Examiner asked the parties to submit statements and replies as to their proposed version of the issues herein. The Examiner, having given careful consideration to all the contentions and proposals submitted by the parties herein, has found and concluded that in order to develop a meaningful record for the establishment of just and reasonable rates for gas produced by pipelines and pipeline affiliates, it was necessary to pursue all substantial as well as minor issues raised thus far. Accordingly, the Examiner compiled and on June 16, 1966, circulated to all parties the attached specific list of issues, (Appendix B) which includes nearly all the items formerly proposed by all participants in this proceeding. As the hearing progressed, it became necessary to revise some of the auxilliary issues outlined in Appendix B, delete others and also raise new ones. It was rather easy to raise pertinent questions. However, it soon became apparent that supporting data for the answers were not readily available. In fact, there was a dearth of evidence on competition. As experience under area rate regulation accumulates, the Commission will be in a position to make more up-to-date and better appraisals of the impact thereof on new gas production. In the meantime, it is necessary to reach a fair and

workable interim solution. The Commission will, of course, desire to take a second look at the situation after the accumulation of adequate data on the competitive impact on production of gas by pipelines. Meanwhile, the independent producers of jurisdictional gas operate under area rates containing special provisions to stimulate exploration of new gas, while the pipelines thus far do not have that advantage.

Because of the difficulty encountered in obtaining detailed data of recent vintage and in order to expedite the proceeding an attempt was made to utilize data accumulated in the other area rate cases. The data initially gathered for purposes of solving certain related though different questions did not always readily supply the answers to the questions before us. Furthermore, much of the data used herein covers the period ended in 1965 or before. We had to make the most of the data readily available in order to focus on the economic, and money raising climate for new gas drilling purposes in the future, probably after 1970. Thus from the same bench mark of 5 years ago, the parties readily painted different economic and gas production pictures for a future period. The widely divergent interests of the "low cost" and "high cost" pipeline producers, the Municipal Group (Consumers), the transmission companies with large affiliate producing

[10059]

enterprises, and the independent gas producers resulted in varied and contradictory presentations. On the basis of the same data developed in our record, the parties made a different forecast for the near future. They used a large canvas and a broad brush to paint the hard-to-focus-on new gas production picture. Since it was necessary to cope with numerous inextricably interwound assumptions, and out of abundance of caution, the pipelines' direct presentation was made in broad terms. Much reliance was placed on general policy allegation and exercises in logic. Many facts were

developed on the record; unfortunately not all proved to be of assistance. Each party was quite effective in pointing out inconsistencies and flaws in new gas pricing and the needs claimed by the others. The parties managed to persuade the Examiner that only qualified reliance can be placed on any of the dated and rather dissimilar tables of facts, which have been assembled to support certain largely self-serving conclusions. Many urged that opposing contentions be taken with a healthy pinch of salt. The parties tried their utmost to be helpful short of volunteering matters that might be detrimental to their own stated position. Consequently, the Examiner must place greater reliance on the aggregate of the presentations of the parties rather than on any individual exhibit or some statement of a particular witness. Nobody presented an airtight case, and at the same time nobody made concessions. Because of the nature and complexity of the case, a detailed analysis of each individual presentation and a specific evaluation of each factual tabulation does not appear warranted. However, each presentation will be summarized herein in order to apprise the reviewing authorities of all major contentions made. The Examiner considered and agreed with much of the rebuttal presentations of the staff and the other parties herein, without following their conclusions nor accepting their specific recommendations. As will be explained in subsequent sections of this decision, most of the gas producing pipelines and affiliates requested the higher area rates, while the consumer spokesmen kept arguing that the present cost-of-service rate regulations prescribing lower rates, must remain undisturbed. All parties attacked the rather weak "modified area rate" proposal submitted by the Staff. No party came foreard with evidence supporting recommendations that could be easily administered, that would be just and fair to all parties and also consistent with the public interest at large. Such a goal, of course, is far easier to require than to accomplish. With this in mind the various presentations will be highlighted in the following sections and the reasons for the Examiner's findings and conclusions will be explained after giving the

[10060]

pertinent historical and the controversial aspects of this case.

II. BACKGROUND OF THE PROCEEDING

This case has grown out of the continuous efforts by some pipeline producers of natural gas[1] to have a "field price," market value, or its equivalent, imputed to their natural gas production.[2] In this regard, the position advocated by the

[1] This section consists of excerpts from the first chapter in Staff Counsel's Brief, as modified and shortened by the Examiner.

[2] The issue whether pipelines should be allowed, in their cost-of-service, a more market-related price for their own produced gas instead of the production costs, has been considered at various times throughout the Commission's history. Perhaps, the most thorough consideration of this issue was in the Natural Gas Investigation (Docket No. G-580). This investigation culminated in two separate reports: the report of Commissioners Nelson Lee Smith and Harrington Wimberly advised adoption of the "field price" pricing method; the report of Commissioners Leland Olds and Claude L. Draper recommend a continuation of cost-of-service regulation (1948). Proposed related Congressional enactment of "field pricing" was introduced in 1947 during the 80th Congress, 1st Session. H.R. 2185, 2235, 2292; S. 734. See H.R. 2569. Such legislation passed the House of Representatives during the 80th Congress, 1st Session (Moore-Rizley Bill, H.R. 4051). See H.R. Rep. No.800. See also H.R. 6645, see 2(f), 84th Cong., 2d Sess. (1956, Harris-Fulbright Bill), *returned without executive approval*, H.R. Doc. No. 342 (February 17, 1956). Significant in consideration of this issue is *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944), affirming *City of Cleveland v Hope Natural Gas Company*, 3 FPC 150 (1942). *Hope* established the basic validity of cost-of-service pricing based on a "prudent investment" rate base. Application of such standard to pipeline and pipeline affiliated produced gas was affirmed in *Colorado Interstate Gas Company v. FPC*, 324 U.S. 581, 597-608 (1945). However, compare Justice Jackson's opinions in both cases arguing that applying cost-of-service pricing to production facilities is unwise due to the lack of economic relationship between original cost and resultant value. 320 U.S. 628-660 and

[10061]

Pipeline Production Group (Pipeline Group)[1] and by certain other pipelines, that independent producer costs should be imputed to their own production reflects at least in part a consistent position that their own production should be valued for rate-making purposes to allow them equivalent unit revenues to those allowed independent producers.

The specific procedural history of this particular investigation began in the *Hugoton-Anadarko Area Rate Proceeding* (Docket No. AR64-1). Having determined in *Phillips*[2] and later in *Permian*[3] to regulate independent producer production on the basis of aggregate industry costs, and area rates based thereon, the Commission was immediately faced with the pipeline producers' claim that a similar method of regulation should be

---

[2]Continued from previous page.
324 U.S. 608-615, respectively. Prominent Commission cases discussing the issue include *Panhandle Eastern Pipeline Company*, 13 FPC 53, 59-77, 103 (majority opinion, 1954), 123-138 (dissenting opinion) which led to the famous *City of Detroit v. FPC* 230 F.2d 810 (CADC, 1955),*certiorari denied*, 352 U.S. 829 (1956). This latter case had held the Commission's use of a "fair field" price to have been illegal because the Commission had not established that the need for the amount of the rate increase allowed had been necessary to achieve its stated objectives.

[1]The fourteen companies which comprise the Pipeline Production Group are: Cities Service Gas Company, Colorado Interstate Gas Company, Humble Gas Transmission Corporation, Kansas-Nebraska Natural Gas Company, Lone Star Gas Company, Natural Gas Pipeline Company, Northern Natural Gas Company, Panhandle Eastern Pipeline Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, Trunkline Gas Company, United Fuel Gas Company and United Gas Pipeline Company.

[2]*Phillips Petroleum Company*, 24 FPC 537, 542-548 (1960), *affirmed sub nom. Wisconsin v FPC*, 303 F.2d 380 (CADC, 1961), *affirmed*, 373 U.S. 294 (1963).

[3]*Area Rate Proceeding (Permian Basin Area)*, 34 FPC 159, 390 U.S. 747 (1968).

[10062]

applied to pipeline produced gas. In this context the Commission decided that within the confines of the *Hugoton-Anadarko Area Rate Proceeding* it should investigate "the extent to which, if any, the rates or cost allowances for pipeline gas production should be regulated on an area basis." The Commission stated that the "factual context" of an area rate proceeding would be "peculiarly useful for evaluating the various problems presented by any shift to area rate method of treating pipeline production." However, the Commission subsequently determined that, given the factual presentation necessary to put the economic and legal policy involved into context, the issues involving the proper costing method to be applied to pipeline produced gas should be examined in a separate proceeding. Thus, on April 13, 1966, the Commission severed the issue of pipeline production from the *Hugoton-Anadarko Area Rate Proceeding* and instituted this investigation (35 FPC 497). In its severance order the Commission specifically directed that this phase of the hearing should separately consider—in Phase I— what rate treatment should be given gas produced from future acquired leases. This present stage of the proceedings is limited to consideration of the rate treatment to be accorded "new" gas.

During the course of Phase I of the proceedings four general positions have been advanced. The Pipeline Group and certain other pipelines and pipeline affiliates have advocated that the Commission allow as part of pipelines' cost-of-service the *same rate* for pipeline produced gas from future acquired leases which would be allowed independent producers under similar circumstances. El Paso Natural Gas Company (El Paso) and the Municipal Gas Group (Municipal Group) have advocated a continuation of the Commission's present cost-of-service policy. Consolidated Natural Gas Company (Consolidated) has advocated cost-of-service rates solely for production from pipeline company leases to be acquired in Appalachia but advocates unmodified area rate for other producing areas. The Commission staff has

[10062]

proposed that, in future cost-of-service presentations, there should be included a "modified area rate" allowance for company produced gas, consisting of pipeline production costs related to leases acquired after the date of Commission's order herein, that these be imputed on the basis of area rate levels but reflecting the rate of return and federal income tax rate components determined on an individual company basis. The Public Service Company of Colorado (Public Service) has suggested that, either under area

[10063]

rate or individual company cost-of-service pricing, an "incentive element" be added to that amount of equity capital which is assigned to production equal to the rate of return allowed independent producers on their equity capital. Public Service would continue to credit federal income tax benefits derived from production operations against the cost-of-service.

Factual and policy presentations were made by 35 witnesses. Pertinent data developed in area rate cases was included as items by reference. There were 5,439 pages of testimony, 73 exhibits, and 36 days of cross-examination of direct and rebuttal testimony. Much factual data about pipeline production has been presented. While evidence has been presented on both a composite and individual company basis (*e.g.*, data arrays), much of the evidence, including staff presentations, have been based upon the composited pipeline production and reserve data collected in the Pipeline Production Questionnaire.

The evidence reveals that for the year 1965 approximately 18 percent of the producing pipelines (referred to as "Group I") reserves and 15 percent of their production is either company-owned or contracted from their affiliates compared with the total of their own, affiliated, and contracted reserves.[1] Group I producers, based on 1965 data, account

[1] Exhibit 6, Table 17 (p. 23, 1965 data).

for approximately 5.5 percent of total United States production and 7.5 percent of total owned reserves.[2] They appear to be heavily gas-oriented and nearly all of their gas production is taken on-system. The unit costs per Mcf of pipeline produced gas vary widely. However, there appears to be a definite pattern of low cost production identified with largely pre-World War II findings of gas and high cost production identified with either more recent transmission company findings or acquisitions of developed or partially developed properties. It also appears that the high costs of recent pipeline acquisitions may be associated with these purchases of developed or semideveloped properties.

[2] Exhibit 54, Sch. 12, Sh. (1), cols (a)–(c), line 1.

[10064]

The hearing was concluded on April 2, 1968, the record was closed on June 17, 1968, Initial Briefs were mailed on July 3, 1968, and Reply Briefs—on August 31, 1968. Appendix A contains a list of parties filing briefs, and Appendix C names the pipeline companies joined as parties respondents.

III. COST-OF-SERVICE ADVOCATES

El Paso and the Municipal Group urged retention of the present cost-of-service regulation for gas produced by pipelines and pipeline affiliates. Consolidated advocated cost-of-service for pipeline produced gas in the Appalachian area, but area rates in all other parts of the country. Public Service of Colorado favored cost-of-service modified only with 12% rate of return on common equity for well-mouth property.

A. *Municipal Group*

The Municipal Group argued that cost-of-service is the established, judicially approved method of regulating gas produced by interstate pipelines subject to FPC jurisdiction

[10064]

and that results achieved under this method fully justify its retention without modification. Their witness Mr. Van Scoyoc contended that:

> Neither Mr. Deutsch nor any other Staff witness testified that regulation of pipeline production on a cost of service basis is impracticable, unreasonable or administratively unfeasible. The record of its administration by the Commission demonstrates the contrary. No question of expediency, therefore, is involved in the issues here presented. (Tr. 4251)

Among other things, the Municipal Group pointed out that gross investment by pipeline companies in production, exploration and development increased over ten times between 1940 and 1961; exploration and development expenses of pipelines and on-system affiliates were 13 times greater in 1962 than in 1940; and owned-reserves of pipeline respondents and on-system affiliates more than doubled and their production more than tripled between 1940 and 1965. This growth in pipeline reserves and production under cost-of-service regulation, the Municipal Group alleged, could never have occurred under area rate valuation which would have provided some companies with adequate returns but caused

[10065]

others to flounder. "The record is completely lacking in persuasive evidence showing that an area rate scheme would result in greater volumes of gas being obtained through pipeline and affiliate production at a reasonable cost to the public."

Use of area rates to price pipeline and affiliate gas, the Municipal Group stressed, has no economic justification. Because pipeline company costs vary widely from average costs underlying area rates, uniform application of the area rate method would deny some pipelines a fair return on investment while affording others windfall profits. Consumers, however, would receive no share of these profits but

rather would be "helpless, captive victims of an uneconomic and woefully unsophisticated regulatory policy . . . ." In addition, the Municipal Group charged that extension of area rates to pipelines and their affiliates would have a severe impact on the bargaining position of pipelines for lower cost gas supplies. "Pipelines having their own or affiliated production would be discouraged from resisting high area rates paid to producers. The removal of incentives for pipelines to bargain with producers for the lowest attainable rate for a given service will increase the pressure to raise consumer rates beyond what is economically justified."

Finally, the Municipal Group claimed that application of area rates to pipeline produced gas would create a "staggering" administrative burden. Among other things, the Group said, it would require: (1) separating pipeline costs to be treated on an individual cost-of-service basis and those to be treated on a group basis, thus compounding problems of cost allocation; (2) deriving and enforcing meaningful accounting systems and standards; (3) setting up and evaluating more voluminous and complex reporting procedures; (4) processing claims for exceptions from area rate treatment; and (5) adjusting area rates, company by company, in order to preserve the benefits to consumers attributable to tax losses from production and exploration activities (under Staff's modified area rates proposal). In this last connection, the Municipal Group stated that Staff's recommended use of tax loss "spillovers" from production activities to reduce tax liability attributable to transmission activities, while intended to preserve an equitable benefit to consumers, would "fall short of its mark." New Production would tend to gravitate to affiliates under Staff's proposal, the Group said, and thereby substantially lessen the chance of available tax losses to lower transmission cost-of-service. In

[10066]

any event, the Group said measurement of a tax loss spillover for rate-making purposes "would present a very difficult problem under area rate pricing. Quantification of this item prospectively without the complete cooperation of company management would be virtually impossible. Obtaining such cooperation would be unlikely."

B. *Public Service of Colorado*

Public Service submitted that the contention of the Pipeline Production Group that the production functions and resultant costs of an interstate pipeline are comparable to those of an "independent producer" and therefore should merit and receive the same treatment as an "independent producer" is not supported by the record in these proceedings. Public Service took the position that a departure from the existing traditional court approved cost-of-service method of rate determination for pipeline companies owning their own production has not been justified in the record of these proceedings, and therefore the existing cost-of-service method now used by the Commission should continue to be employed in pricing gas involved in these proceedings. Independent producers in the *Permian* case, *supra,* and in the *Southern Louisiana Area Rate Proceeding,* AR61-2, Opinion No. 546, September 25, 1968, have been given the recognition of incentive to encourage further discovery and production of gas reserves. Public Service believes that a comparable incentive should also be given pipelines having their own production as it relates to their production activities. Public Service urged that a modification of the cost-of-service as it applies to production facilities should be made similar to that which the Commission granted in *Panhandle Eastern Pipeline Company,* 25 FPC 787. Public Service submitted that a departure from the Commission's traditional cost-of-service basis for the regulation of pipeline production would not be in the best public interest. The Commission should continue to regulate the production activities of an interstate pipeline upon and in accordance

with the existing cost-of-service method, modified only with 12% rate of return on common equity for well-mouth property.

C. *El Paso*

It was El Paso's position that when, in the future, a pipeline is itself engaged in natural gas production operations in support of its utility-type function, then the gas produced from these operations should continue to be priced on a cost-of-service basis.

[10067]

Further, when a pipeline affiliate sells gas to its parent, those sales are, in El Paso's opinion, also in support of the pipeline's utility-type function and that gas should be priced on a cost-of-service basis.

Finally, when a pipeline affiliate is engaged in gas and other hydrocarbon production operations—and is selling the gas it produces to thrid parties—such affiliate is not in El Paso's opinion, functioning in support of its parent's utility-type function but is functioning as a independent producer, and there is no reason why gas so sold should not be priced as the Federal Power Commission now prices sales by independent producers; that is, at area rates.

El Paso's Vice President, Mr. V. M. Plummer, testified that if natural gas could be purchased by a pipeline at the time it is required and under appropriate conditions to satisfy new or growing markets, the need for extensive production activities by such pipeline would not be prominent, Mr. Plummer testified that in the period from 1947 to 1950 casinghead gas accounted for between 60% and 75% of El Paso's total receipts, that for the period 1950 to 1960 this figure ranged between 40% and 60%, and that while casinghead receipts have since decreased to about 30% of the total gas utilized each year, the quantities being made available and taken by El Paso each year continue to increase. Mr. Plummer stated that where such large quantities of

[10067]

casinghead gas are available during the early days of the month, which are subject to being completely shut in during the latter part of the month, it is necessary for El Paso to have an enormous quantity of gas-well gas available to compensate for these wide fluctuations. He testified that no adequate storage areas have been identified in El Paso's operating area which could help alleviate the need for such large supplies of gas-well gas.

Mr. Plummer's Exhibit 20 contained figures showing (1) company-owned proved reserves at year end and—on the same basis—(2) proved reserves under gas purchase contracts for the years 1946 through 1965. He testified that these reserves have served the exact purposes for which they were originally acquired, *i.e.*, they have increased El Paso's total gas supply and have enabled it to even the fluctuations in cashinghead gas availability. He stated that El Paso's company-owned production permitted the company to provide adequate service to existing and new markets which, without it, would not have been possible. He testified that as of the end of 1965 El Paso owned approximately 8.6 trillion cubic feet of natural gas reserves which

[10068]

constituted approximately 40% of the total reserves owned by all producing pipelines.

In describing how El Paso's production activities in the past have differed from those conducted by independent producers, Mr. Plummer pointed out the principal and significant difference was the nature of El Paso's activities in acquiring its company-owned supplies. He reiterated that El Paso was forced into production activities not only to enable it to render new gas service but also to continue existing gas service. In contrast, he stated that the independent producer has two choices, *i.e.*, (1) whether to enter a particular gas field and (2) the purchaser and market to which it will sell the gas. He contended that El Paso's utility-type responsibility did not provide El Paso these

choices. It was essential that El Paso carry on these activities for the benefit of El Paso's own customers. The gas which was developed was made available for the use of said customers. As policy witness, Mr. Plummer said that El Paso would engage in production activities, only to the extent that company-owned production would be necessary to assure the availability of adequate supplies for El Paso's customers. He stated categorically that if independent producers are successful in developing the quantities required and that if this gas can be economically obtained under conventional gas purchase contracts, El Paso's activities will not be extensive. He testified that El Paso's anticipated limited activities in the future will (1) stimulate exploration activities of independent producers in areas in which El Paso is interested and (2) will enable El Paso to move promptly to find and develop its own gas for its customers should the independent producers fail to bring forth and make available sufficient quantities of gas through conventional gas purchase contracts.[1]

[1] Official notice is taken of the recent "Project Gasbuggy" in which El Paso has participated with the Atomic Energy Commission and the Bureau of Mines. The underground detonation of a nuclear device in New Mexico to determine the feasibility of using nuclear explosives to increase gas production was apparently successful, and further tests will follow. The U. S. Bureau of Mines has estimated that future success with these, the atomic explosions could double the commercially recoverable gas reserves of the U. S., but the final answer may not be known for as long as five years.

[10069]

In conclusion, Mr. Plummer urged that El Paso's future pipeline production activities be accorded rate treatment which will afford the company the opportunity to recover its reasonable costs and earn a fair return. He stated categorically that El Paso's activities will not be conducted in a manner similar to the production activities of an independent producer but that they will be integrated with El Paso's

[10069]

utility-type function and, being utility in nature, they should be accorded utility-type rate treatment.

---

[1] Continued from previous page.
"El Paso is in excellent position with respect to gas reserves, which have been built up by exploration and purchases. These reserves are now about 38 trillion cubic feet, with a life index of nearly 23 years (the longest in the industry). While some of these reserves will be divested along with the Northwest properties, the company will still retain about 29 trillion of or almost 10 percent of total U. S. proven gas reserves."
Source: Article by Mr. Owen Ely in the January 2, 1969 issue of The Commercial and Financial Chronicle.

[10070]

IV. AREA RATE ADVOCATES—GROUP I PIPELINES

A. *Pipeline Group*

The chief advocates of the area pricing method are the Pipeline Production Group (Pipeline Group), consisting of fourteen pipeline company respondents, most of which are producers of natural gas. The group members are: Cities Service Gas Company, Humble Gas Transmission Corporation, Colorado Interstate Gas Company, Kansas-Nebraska Natural Gas Company, Lone Star Gas Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipeline Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corp., Trunkline Gas Company, United Fuel Gas Company, and United Gas Pipeline Company.

The Pipeline Group was organized in response to the suggestion of the Commission and the Examiner that parties make joint evidentiary presentations so as to avoid duplication. This case was presented on behalf of all members of the group, except for Humble Gas Transmission Company, which made its own presentation and filed its own brief. Individual members reserved the right to express their po-

sition separately. As will be reported subsequently, some made additional presentations.

The Pipeline Group alleged that there is a present and growing need for pipeline production to meet the sharply increased demand for natural gas; that individual company cost-of-service regulation of natural gas production is impractical and not in the public interest; that pipeline companies can explore for and produce significant new volumes of natural gas only if they are accorded full parity with independent producers; that this record contains factual and legal basis for treating pipeline producers as a group similarly to independent natural gas producers.

The Pipeline Group urged application of the area rate method adopted for independent producers to both pipeline producing departments and pipeline affiliates. Two principal reasons advanced in support of parity treatment were: (1) natural gas production is not a franchised business and should be open to all on the same basis without handicap and under the same regulatory ground rules; and (2) pipeline production offers potential for meeting future demands for natural gas in a period of growing supply scarcity. In the latter connection, the

[10071]

Pipeline Group stressed that the demand for natural gas in interstate markets has been increasing at a rate substantially faster than the demonstrated capacity of the industry to find new reserves, and that every forecast indicates a steadily widening gap between replacement supply and increased demand. While natural gas pipeline companies have the greatest stake in finding such reserves because they have the major investment commitment to the natural gas industry, owned-reserves of producing pipelines declined on average by approximately 30% during the period 1958-1966. Accordingly, the natural gas industry has been forced to rely increasingly upon independent producers to furnish the gas supplies required for current and future demands. However,

[10071]

exploration and development activities of independent producers have allegedly not kept pace with the growing demand for gas. Furthermore, the Pipeline Group said, gas production is only a very small part of the independent producers' business; approximately 65% of the gas moving in interstate commerce is produced by some 23 companies which, for the most part, are fully integrated oil companies with heavy investments in crude oil production and transportation facilities, refining and processing facilities and hydrocarbon product marketing organizations. "Given these facts, there are no automatic, economic incentives assuring any degree of independent producer effort to find and develop natural gas reserves." Also, the Pipeline Group added, growing intrastate demand offers an alternative market which could absorb an increasing percentage of future gas discoveries by independent producers. Accordingly, "the maximum possible exploratory effort–including that of pipelines–should be encouraged."

The individual company cost-of-service method, the Pipeline Group contended, has been abandoned by the Commission for independent producers. The Commission's reasoning in supprt of such abandonment, the Pipeline Group submitted, is equally applicable to all natural gas production activities, regardless of the type of company engaged in them.

B. *Degree of Comparability*

The Pipeline Group presented five witnesses in its direct case in support of its broad "parity argument" urging that gas produced by pipelines and pipeline affiliates should be priced on a straight area rate basis.

Witness Elmer, the chief executive officer of Texas Gas Transmission Corporation, testified as the "policy" witness for

[10072]

the Pipeline Production Group.

He urged so-called "parity" of treatment for pipelines and for independent producers.

> ". . . the comparable characteristics of all producers generally justify and require utilization of data for the various calsses of producers in reaching an end result which would then be applicable to each."

Witness Elmer stressed that there has been an increase of joint operations between pipelines and independent producers. He emphasized the importance of pipelines actively engaged in production operations and stated that the decline in pipelines exploratory effort is due principally to the difference in rate treatment accorded pipeline production. This witness predicted that future pipeline production activities would decline if so-called "parity" of treatment were not granted. Witness Elmer described advantages which he believed flow from pipeline production activity. He said that area rate pricing of pipeline production would not adversely affect the independent producers, and he contended that area rate pricing of pipeline production would not increase overall costs to the consumer.

Witness Elmer relied on exhibits and testimony of other witnesses to substantiate his contention that all producers, pipelines, affiliates and independents, have comparable characteristics. He did not prepare studies to demonstrate the true extent of and type of joint interest operations. The entire basis for his conclusion that area rate pricing is appropriate for pipeline production is based on a general assertion that pipelines' and independent producers' production activities are entirely comparable.

Witness Dickinson, a former Vice President of Production for Natural Gas Pipeline Company of America, testified that in 1919 when he commenced work in the producing industry, there were a substantial number of pipeline companies which owned or controlled portions of their gas supplies but that in recent years interstate pipeline companies have become increasingly dependent upon purchased gas. Witness Dickinson also testified that there are no substantial differ-

ences in the techniques and methods available to pipeline producers as compared with other producers, *i.e.,* lease acquisitions, geophysical testing and evaluation, drilling operations, electric log analysis, etc.

[10073]

Although testifying that, theoretically, pipeline companies should be capable of achieving comparable results with other producers, Witness Dickinson conceded that even during the early years of interstate transmission operation, *i.e.,* 1931 to 1946, when the price of gas in the field was not regulated by the Federal Power Commission, pipeline companies did not engage in wildcat activities looking to the discovery of natural gas but rather engaged in developmental work on properties acquired within proven areas.

Witness Jones, Assistant Manager of Rates and Research for Panhandle Eastern Pipeline Company, in attempting to establish comparability among pipelines, affiliates, and independent producers contended that: (1) there is substantial joint interest participation among these three segments of the producing industry; (2) future pipeline production costs would be comparable to future costs of the other two segments for new gas, and (3) while there are variations among individual company costs, there are no significant variations among the aggregate costs of the three segments of the producing industry.

The figures which the Witness Jones used are derived from combined data for a number of companies with little or no joint interest activity, and data for a few companies which had substantial joint interest activity. Thus he obtained a composite joint interest participation figure (exclusive of the Appalachian area) of 49% for the pipelines and affiliates combined. Witness Jones stated that the joint interest percentage for the Appalachian area was only 2%. This contention was successfully rebutted by El Paso's Witness Field who pointed out that it is not proper to ignore the joint interest position of the 13,574 gross wells in which

[10073]

pipelines own an interest in the Appalachian area. Those wells are nearly twice the number of pipeline gross wells that Witness Jones relied on to reach his conclusion, and it should be noted that the Appalachian area produces about 1/6th of the total pipeline production in the United States.

Schedule 14 of El Paso's Witness Field's Exhibit 58 shows that the joint interest percentage varied considerably from pipeline to pipeline. Twelve of the 20 pipeline companies had a joint interest percentage of less than 13%. Ten of them had a joint interest percentage of less than 4% and only four of the 20 had a percentage as high as the 49% testified to by Witness Jones. Further, the tabulation below shows that five[1] of

[1] Witness Jones' Exhibit 37 did not show costs per unit for Trunkline Gas Company.

[10074]

those six companies with relatively high joint interest percentages did not have identical per unit cost characteristics as measured by Witness Jones' own Exhibit 37 (revised):

	Unit Production and E & D Costs per Mcf
El Paso Natural Gas Company	46.18¢
Kansas-Nebraska Gas Company	8.71¢
Southern Natural Gas Company	18.47¢
Tennessee Gas Pipeline Company	111.84¢
Texas Eastern Transmission Corporation	26.33¢

All of the costs computed by Witness Jones for the pipelines with high joint interest percentages are substantially different than the average for independent producers—which demonstrates a lack of sensitivity to any alleged joint interest common characteristics.

Finally, the 49% figure used by Witness Jones is disproportionately weighted by one large pipeline, *i.e.*, El Paso Natural Gas Company. As shown on Schedule 15 of Exhibit 58, El Paso's 1,451 joint interest wells represent 55%

[10074]

of all joint interest wells for the pipelines used by Witness Jones. Further, those wells represent 61% of the 2,392 wells shown in Schedule 1 of Exhibit 35. This disproportionate weighting is even more significant since, of the 1,451 El Paso joint interest wells only 18% were truly joint lease wells, 34% were joint because of communitization and 48% were joint because of unitization. Thus, as Witness Field pointed out, 82% of the alleged joint wells for one company which represented 61% of the joint wells used by Witness Jones for all pipelines were not joint for all phases of the exploration and production process.

In his Exhibit 36 Witness Jones purported to present an analysis which compared the future new-gas cost for pipeline producers with the future new-gas cost for the producing industry as a whole and attempted to demonstrate that the costs were very similar. Witness Jones' conclusion was challenged in Schedule 18 of Witness Field's Exhibit 58. The latter schedule compares the cost components computed by Witness Jones with those computed in the Permian case and gives the wide percentage range of cost variations. For example, the net liquid credit used in Permian case was 68.5% higher than that used by Witness Jones, and because it was a credit, the excess works to offset the substantial excess debit for total exploration and development costs.

[10075]

Although the Pipeline Group contends it is the total that is important, this is questionable, for if there were no difference between pipelines and independents there would be little or no difference among the various cost components. The fact that there are substantial differences in the cost components weakens the contention of the Pipeline Group that pipelines and independent producers are comparable.

Witness Jones' conclusion regarding similarity of new-gas costs for pipelines and independent producers is not convincing. Witness Jones conceded on cross-examination that the ratio of reserve additions per foot drilled—commonly

referred to as the productivity of drilling ratio—is a very sensitive and important factor in the new-gas computation. However, Witness Jones attempted to calculate a new-gas cost for pipelines despite substantial inherent problems in the methodology and his recognition of the sensitivity of the cost computation to the productivity of drilling computation.

Witness Field testified that, a major problem in making a new-gas cost computation is to determine and use a productivity of drilling figure which is representative of the future. Witness Field pointed out that if a past time period is used, the data for such period must be carefully evaluated to make sure no trend is obvious which would indicate that the figure for the future would be different than that obtained for the past. Witness Field showed that Witness Jones did not test his data for an apparent trend since, for the period 1955-1962 used by Witness Jones in his productivity computation, an obvious and significant downward trend existed.

Witness Jones said that he had added Pacific Northwest's reserves to El Paso's reported Form 2 reserves to determine El Paso's reserves. Thus, the 661 Mcf productivity of drilling figure includes the acquisition of the Pacific Northwest reserves by purchase. Witness Field showed that the 661 Mcf figure would decline to 434 Mcf if the Pacific Northwest reserves were properly deducted from the computation. If the data for only one year, 1957, were excluded, the figure would be 285 instead of 661. If only one company, El Paso Natural Gas, were excluded, the ratio would change from 661 to 561. If a comparison were made of the productivity figure for the first half and second half of the period Witness Jones used, the result would be:

1955-1958	:	1,452.4
1959-1962	:	(301.3)
1955-1962	:	660.5

[10076]

Witness Field also demonstrated that because of the responsiveness of the overall cost computation to the highly sensitive productivity computation, the new-gas cost methodology developed in the *Permian* case is not compatible with cost determinations for relatively small groups of companies such as the pipeline group used by Witness Jones in Exhibit 36.

In the *Permian* case the Commission has recognized that there are fundamental differences between large and small producers and this record clearly shows that pipelines are not "large" producers when compared with the major oil companies whose statistics were so meaningful in the *Permian Area Rate Proceeding.* The evidence in this record, including Staff's evidence, clearly demonstrates that pipelines operate on a regional basis rather than on a national basis and that they have almost invariably concentrated their production in areas adjacent to or within economic reach of their respective pipeline systems. There the Examiner held:

> "The basic difference between the small and the large producer is that risks of the business are materially different for each. The small producers exploratory activity is not extensive enough to afford him the likelihood of achieving average results, whereas the large producer over the years can approach this result." (34 FPC 159 at 360)

The Commission shared this view in Opinion 468, 34 FPC 159 at 234.

Witness Jones prepared Exhibit 37 to demonstrate that there are high cost and low cost producers within the three groups. He insisted that the variations are not between the segments but among the individual companies. However, Witness Field's Schedules 19 through 21 of Exhibit 58 shows that 59% of the independent producers used by Witness Jones were in quartiles immediately surrounding the median, whereas only 41% were in the quartiles representing

the "extremes." While the positioning for the affiliates varied somewhat, only 27% of the pipelines surrounded the median while 73% were in the "extremes." In his rebuttal testimony, Staff Witness Bass called attention to the same discrepancy between Witness Peck's conclusions and the Pipeline Group's own data as compiled by Witness Jones.

> "Q. Are there other factors which might differently affect the risk of pipeline production vis-a-vis independent producer production?

[10077]

> "A. The advantages of having integrated transportation and producing functions might reduce the risk of pipeline production in various ways. In fact, the advantages to pipeline production testified to by various pipeline witnesses such as "swing," etc., if true, would tend to reduce pipeline risk. Most advantages testified to relate to integrating production and transportation functions to get a more efficient overall operation. Such added efficiency would of course add to investor attractiveness. Furthermore, low quality pipeline production may be less of a risk because pipelines may be able and willing to blend poor quality packages of their own gas with their other supply or may be better able to absorb high cost packages of their own gas whereas producers must dispose of high-cost packages of gas for the best price they can obtain. ***" Tr. 498.

It should be noted that Witness Jones' unit cost figures contained in his array in Exhibit 37 are not proper unit cost-of-service determinations for pipelines. As pointed out by Witness Field, Witness Jones' calculations included a 12% return for pipelines, did not include a production tax component, computed the royalty by the net working interest method, and allocated joint production costs.

Witness Anderson, Manager, Rates and Economics of Panhandle Eastern Pipe Line Company, also attempted to establish comparability among the three segments of the

[10077]

producing industry. On cross-examination, this witness conceded that although he had testified that he had used the AAQ responses of 15 pipelines, 17 affiliates and 57 producers, his Exhibit 23 contained data only for 9 pipelines, 13 affiliates and 47 independent producers. He further stated that several of the pipeline producers had reached a relatively "inactive status." Witness Anderson's sample had narrowed to only 3 pipelines by the year 1962, the final year of these data. Witness Anderson's use of averages for the Pipeline Group raises problems, for it fails to consider obvious substantial variations among the pipelines, and the averages were inordinately sensitive to single company extremes. By using a relatively long time period (1955 through 1962), Witness Anderson alleged apparent comparability whereas had he used the data for more recent years, he would have shown a lack of comparability.

[10078]

Witness Anderson also attempted to use drilling costs per foot to demonstrate comparability among the three producing segments. He compared the cost per foot for total productive wells (both oil and gas), whereas his Exhibit 26 presented the data for total productive wells and total gas wells shown separately. Schedule 27 of Witness Field's Exhibit 58 successfully challenged Witness Anderson's use of the cost-per-foot data for total productive wells, both gas and oil, instead of total gas wells to determine comparability. Witness Field showed that the cost for all productive wells varied substantially from the costs for gas wells drilled by affiliates and independents. Also, the cost data for gas wells definitely reveals noncomparability between pipelines and independents.

Witness Field testified that the foregoing noncomparability was not caused by different levels of efficiency in drilling but rather by the fact that pipelines do behave differently in their drilling activities, as compared to independents and affiliates. He explained that the unit of cost

causation, the per foot of well, is not a homogeneous unit. Pipelines emphasize drilling in different areas and drill a different mix of wells than do affiliates and independents. The pipelines, in addition to emphasizing gas-well drilling, emphasized developmental and shallower drilling more than do the affiliates and independents.

Witness Anderson also attempted, in his Exhibit 33, to demonstrate that there has been a decline in exploratory activity, and from this Witness Peck concluded that, since pipelines and independents had comparable characteristics, the alleged decline must have been due to alleged different rate regulatory treatment. Since the so-called "comparability" testified to by Witness Anderson and relied on by Witness Peck does not in fact exist in any substantial amount, it is improper to attribute the decline in exploratory activity solely to the so-called differences in rate treatment.

Witness Peck, an eminent economist and Yale University Professor, stated that he had no experience in the oil and gas industry, and that he had applied his general skills as a market organization economist to the following two questions: (1) Is there a significant economic difference between the natural gas production activities of pipeline producers (including separate corporations affiliated with pipeline companies) and the independent producers which would justify distrinct regulatory policies for the production activities of these two groups; and (2) What would be the effects of individual company cost-of-service regulation of the production activities of pipeline

producers?

Witness Peck said that he personally had made no empirical investigation but instead relied entirely on the statistical cost material gathered by Witnesses Jones and Anderson, the technology testimony given by Witness Dickinson, and the testimony of Messrs. Elmer and Dickinson, that risk and uncertainty were similar, and that the sources of investment

funds were similar. Witness Peck testified that, based on these cost causing factors, pipelines and independent producers were comparable. An expert witness need not go to Niagara to know that water runs downhill. However, a conclusion based on testimony of a few witnesses, and without analysis of the pertinent rebuttal testimony, has its limitations.

Witness Peck has concluded that since costs were allegedly comparable for the three segments of the industry, different rate making treatment is not economically justifiable. However, Witness Peck stated he concluded that costs were comparable by using Witness Jones' new gas cost comparison on Exhibit 37 and the drilling cost data of Witness Anderson. When asked if the drilling costs he used were for both oil and gas wells, he said they were. Then, when asked if the Commission in the *Permian* case had used cost-per-foot data for both gas and oil wells to compute successful wells cost, he answered:

> "I don't know that. I am trying to recall now. I am not sure. It would be my understanding that it would use both."

However, it appears that the Commission did use gas-well gas cost per foot and not oil well data in unit cost determinations for gas. 34 FPC 159, 192, 197 and 377-379. An economic witness' conclusions based on cost comparability are not persuasive when the data upon which comparability is based is not convincing.

Further, the cost per Mcf data which Witness Peck relied on to determine that the three producing segments of the industry had similar quartile distributions, in fact showed substantial variations both in rankings and in average cost per Mcf for such producing segments of the industry. Witness Peck said that the alleged decline in exploratory activity testified to by Witness Anderson occurred because of the difference in rate regulatory treatment between independent producers on the one hand and pipelines on the other. However, the comparability assumed by

[10080]

Witness Peck did not exist for factors such as success ratios and cost-per-foot of drilling. Therefore, it is difficult to attribute the decline in exploratory activity solely to the so-called differences in rate treatment.

Witness Peck's testimony about the use of the manufacturing-concern definition of "efficiency" in his cost analysis is not helpful in the instant proceeding. As Staff Witness Deutsch pointed out, the so-called "efficiency" in drilling has a large element of "luck" involved and that the finding of gas has nothing to do with a manufacturing-concern concept of "efficiency."

With respect to the use of unmodified area rates for pipeline production as proposed by the Pipeline Group, El Paso effectively argued that the Group relied upon and attempted to prove one principal proposition—that pipeline production is comparable to natural gas production of independent producers in all fundamental respects and should therefore receive parity of rate treatment. However, El Paso claimed, the Pipeline Group's case was based mostly upon composited data which, when tested by cross-examination and rebuttal analysis, "shows not that pipelines and independent producers are comparable but rather that there are vast differences between pipelines and independents and, indeed, among pipelines themselves." Thus, rather than establishing comparability, the Group's data demonstrates "wide variation and lack of comparability."

Area rates for a regulated class are proper when the evidence is representative and ample in quantity to measure with appropriate precision the financial and other requirements of the parties concerned. See *Tagg Bros. v. United States*, 280 U.S. 420; *Acker v. United States*, 298 U.S. 426; *United States v. Corrick*, 298 U.S. 435; *United States v. Abilene & S. R. Co.*, 265 I;S. 274, 290-291; *New York v. United States*, 331 U.S. 284; *Chicago & N. W. R. Co. v. A., T. & S. F. R. Co.*, 387 U.S. 326, 341.

[10080]

The Examiner concurs with El Paso's presentation that there was no evidence in *Permian* and there is no convincing evidence in this proceeding which indicates that the costs of most pipelines will "tend to approximate industry averages in the long run." The Staff's cost data in the record of the *Permian* proceeding did not even include pipeline data (Staff stipulation at Tr. 2162 and Tr. 2227 in this proceeding), and the record herein indicates that unit cost data for pipelines have extremely wide variations.

[10081]

The Commission found that the data provided for flowing gas by the major independent producers with respect to their national production costs was fully representative of Permian Area flowing gas costs for all independent producers. The Commission convened the instant hearing to determine the propriety of applying area rates to the respondents in this proceeding. Since the only data in the record shows that pipelines, as a group and individually, do not have costs comparable to those national costs used in the independent producer area rate proceeding, and are otherwise not properly comparable in their activities, it is not proper to fully apply independent producer area rates to such pipelines.

While the small producers made a somewhat similar argument in the independent producer area rate proceedings, there are important differences between the pipelines and the small independent producers. First, the deviation from average cost for pipelines is much greater than for independents. Second, the pipelines are already being regulated under an effective method of regulation which gives recognition to the individual cost pecularities; whereas, the alternative in the case of the small independent producers, seemingly would have been either (1) exemption from area rates or (2) individual cost-of-service hearings for the over 3,000 small producers involved in production of gas being sold in interstate commerce. As to the former, the Com-

mission found that this would possibly allow a "penetration of rate ceilings" which "could be seriously disruptive of a pattern of uniform area ceilings." (34 FPC at 325). As to the latter, the holding of individual cost-of-service hearings would undoubtedly, as a pragmatic matter, mean that adequate regulation for about 3,000 small independent producers would be impossible under existing law. (*Phillips Petroleum Company*, 24 FPC 537 at 547).

The record demonstrates that the cost-price determined for independent producers in the *Permian* decision is not representative of the costs of pipeline producers. Pipelines, unlike the major producers, have confined their drilling activities essentially to areas adjacent to their respective systems and have not operated on a national basis. Pipelines have emphasized: (1) drilling for gas rather than hydrocarbons in general, (2) developmental drilling, and (3) shallower drilling. The differences in location and emphasis of purpose have caused the success ratios and drilling costs for pipelines to be noncomparable with those for independent producers.

[10082]

Witness Jones' array data indicated that only 27% of the pipelines had costs which were within the quartiles surrounding the median for all groups, while 59% of the independents had costs so positioned in the array. The average percentage deviation (from the weighted average for all groups) for pipeline costs was 103.6%, whereas for independents it was only 19.1%.

Only 6.6% fo the independent producers' volumes had costs (as computed by Witness Jones) which were more than 65% positive or 35% negative deviation from the average cost for independent producers, affiliates and pipelines—while 74.8% of the pipelines' volumes had costs with such deviation. Moreover, the table indicates that 84.0% of the independent producers' volumes had costs which were with in 30% of the average cost—while 86.6% of the pipelines'

volumes had costs which were more than 30% above or below the average cost.

The foregoing leads to the Examiner's finding that the present record does not support a sudden and complete shift to area rates for pipeline produced gas.

C. *Incentives to Expand Production of Pipelines*

Mr. Elmer, the policy witness for the Pipeline Group, urged that the Commission should allow pipelines the same rate which is allowed independent producers, regardless of what equity return would be created by such rate, because this will encourage additional exploration by pipelines.[1]

An attempt by the Commission to similarly increase pipeline producer rates was reversed by the courts. *City of Detroit v. F.P.C.,* 230 F.2d 810 (CADC, 1965), *certiorari denied,* 352 U.S. 829 (1956). There Judge Prettyman said:

> While as we have indicated the Commission may be empowered to consider some of these factors it must also, and always, relate its action to the primary aim of the Act to guard the consumer against excessive rates. If the Commission contemplates increasing rates for the purpose of encouraging exploration and development, or the ownership by pipeline companies of their own producing facilities, it must see to it that the increase is in fact needed and is no more than is needed, for the purpose.***

[1] Pipelines (not counting affiliates) account for approximately 5.5 percent of total U.S. production and 7.5 percent of

(continued on next page)

Claims for an increased rate through allowing an independent producer rate of return fall within the prohibition and purpose of *City of Detroit, Supra.* The issues is not whether application of the independent producer rate of return to pipelines might not have certain stimulating effects

on pipeline exploration and development. The issue is whether the proposed increase in the pipeline rate of return on their production properties has been justified in the amount claimed. Since there has been no direct evidence demonstrating either the need for additional supply or, the necessary amount of such incentive, such additional allowance cannot be allowed.

Pipeline witnesses have contended that intangible benefits of pipeling production would justify such "encouragement." They claimed that pipeline producers can obtain advantages in terms of "contract" provisions, as opposed to quality or price advantages. That is, by not being contractually limited in the use of their own supplies as to production rates of take and related "take-or-pay" clauses, or other contract terms, pipelines have greater "flexibility" in the use of their own supply.

Claimed rights to additional rate allowances for various allegedly liberal contract provisions have been previously advanced and have been previously denied. *El Paso Natural Gas Co.* 35 FPC 40, 43-45 (post-*Permian* "in-line" certificate proceeding, 1966), *set aside sub nom. Phillips Petroleum Co. v. F.P.C.*, 377 F.2d 278 (C.A. 10, 1967), *reversed sub nom. California v. Phillips Petroleum Co.*, ___U.S.___, 36 U.S. Law Week 3440 (May 20, 1968). Such claims are usually tantamount to demands for increased rates above cost in order to achieve certain objectives.

Staff Witness Raymond's analyses indicate an inconclusive correlation between reserve-production ownership and take-or-pay for prepayment positions of pipelines. The data does not establish that reserve-production ownership is a cost-saving benefit to pipelines. Staff Witness Deutsch testified that he has not been able to ascertain any advantage in owning reserves and production with respect to forfeited gas. He pointed out

[1]continued
U. S. reserves. While their production is important, compared with major independents, pipeline producers tend to be small and "it is to

[10083]

doubted that pipeline companies can be relied upon for a general oil and gas supply assurance." (Witness Bass)

[10084]

that so long as there are no forfeitures for prepaid gas, the essential cost associated with prepaid gas is an interest charge. While there is a cost associated with payment for gas supplies in advance, there is also a cost in connection with the under-utilization of productive capacity to avoid prepayments. Staff Witness Beirne's exhibits show that while formerly pipeline producing companies had been attaining greater flexibility from their own production than from their purchases, this alleged benefit is diminishing gradually. Staff Witness Zabel's exhibit shows that withdrawal rate of pipeline company-owned reserves is 30 percent below that of independent producers and 40 to 50 percent below that of affiliated producers.

Witness Deutsch reasoned that either pipelines are husbanding the lower cost "old gas" or lowering withdrawal rate of pipeline produced gas. This alleged flexibility advantage results in extra cost to consumers.

The principal alleged advantage of pipeline production is its providing what is known as "swing," or, in other words, "the ability of a pipeline to control takes from gas supply sources which would permit the pipeline to obtain variations in gas inputs into its own system."

Staff Witness Beirne demonstrated that the ratios for the total inputs of gas into the systems of those pipelines with production do not significantly differ from the ratios for the same pipelines' inputs excluding company-owned production. This indicates that the pipelines are able to contract with independent producers for swing flexibility. Staff Witness Bass testified, that "The one advantage of pipelines using their own production to obtain flexibility, which appears to have some tangibility, is the use of this flexibility to avoid additions to prepayment obligations." For the years 1958-1965, the cost savings to the producing

pipelines of avoiding prepayments was approximately 5/100 of a cent per Mcf.

The question is "whether a pipeline's utilization of its own production properties to obtain additional flexibility is more costly than any incremental flexibility thus obtained is worth."

> "By its very nature, pipelines' swinging on their own production usually results in comparatively low takes, and, therefore, in reduced production rates." (Witness Bass)

[10085]

The potential increase in the production return cost alone from increasing the depletion period was considered by Staff Witness Bass. He contended that comparing these additional costs to pipelines using their own reserves to obtain greater supply flexibility and the amounts of potential cost savings from such use, it seems clear that, as a generality, such savings are not worth their costs. Extensive use of company reserves for obtaining flexibility sometimes may be of advantage to a company. "But the evidence clearly points to the fact that any added advantage would be seldom worth its increased costs." Moreover, it was indicated that flexibility from company-owned production compared with purchased gas is diminishing. Since modern day pipelines operate at increasing high annual load factors, the need for company-owned production providing swing capability, vastly exceeding that available under producing contracts, has deminished. The Commission has already prescribed certain daily contract quantity and make-up provisions in future contracts which might be detrimental to natural gas consumers, thereby limiting the potential harm which flexibility is supposed to mitigate.[1]

The other alleged advantage special to pipeline production is the stated greater propensity of pipelines to explore near their transmission lines. However, it would be equally advantageous for independent producers to explore near

[10085]

existing transmission lines. The Examiner fails to see how this justifies higher rates.

---

[1] The extent to which pipelines actually are using their own reserves for flexibility purposes was questioned. Staff Witness Beirne's study indicated that, while pipelines do appear to swing on their own reserves to a considerable extent, it could not be concluded that the overall effect on pipeline operations would be substantial. Furthermore, a comparison of the ratios of average "takes" for the month's minimum and maximum use for both purchased and company owned reserves shows relatively slight differences for gas from the two sources.

[10086]

production department benefits in obtaining better overall contract terms. The Examiner considers these claimed advantages quantitatively unproven.

Accordingly, the Examiner finds and concludes that it has not been demonstrated in this proceeding that increased pipeline production of gas would result in tangible benefits to the public interest justifying increased rate of return for the production function.

D. *Consolidated Group*

Consolidated Gas Supply System, National Fuel System, Kentucky West Virginia Gas Co., Philadelphia Gas Works and Public Service Electric & Gas Co. (The Consolidated Group) made a joint presentation and also filed joint initial and reply briefs. The Consolidated Group took the position that pipeline-produced gas provides many benefits to the pipelines engaged in such production, to their utility customers and to the ultimate consumers of natural gas. The Consolidated Group advocated a regulatory policy that will encourage pipelines, in the future, to explore for, develop and produce their own reserves. It contended that this encouragement would be provided if the Commission were to apply area pricing methods to gas produced by pipelines in the major southwestern producing areas.

The Consolidated Group argued, however, that production operations in the Appalachian Area are atypical, that

the new gas pricing method adopted by the Commission is inappropriate for that area, and that the cost-of-service method now in use there has served a useful regulatory purpose and should be continued.

The Consolidated Group cited evidence that at the end of 1962, pipeline and affiliated producers owned 13,354 gross wells located outside the Appalachian Area. Forty-nine percent of these wells were owned jointly with others (Exhibit 35). For pipelines alone, the comparable figure is about 35%. Joint operations allegedly entail identical risks.

The geological, geophysical and technological aspects of the exploration, development and production of gas reserves are allegedly identical for both pipelines and independent producers. Both are able to follow the same methods, use the same tools and apply the same techniques. Many factors are completely uniform or standardized. The drilling operations are also similar. As a general rule, neither the independent producer nor the pipeline

[10087]

producer actually performs the drillings of the wells. Ordinarily, this work is done by drilling contractors who make their services available on the same basis to both pipeline and independent producers. In view of these widespread practices in the industry, "it follows that the cost of the entire operation for a particular well would not be affected materially by the classification of the operator."

Supply Company President Corrin testified that:

> "The existence in a pipeline of the alternative of turning to its own reserves will enable it to make the most timely and economic purchases of uncommitted reserves held by producers. Even under regulation there will still be some cyclical movement of field prices. Pipelines owning their own reserves will be in a better position to take advantage of this movement.

* * *

[10087]

"With this flexibility, the pipeline can obviate the need of writing into purchase contracts unusual flexibility provisions which might require premium prices.

"The existence of valuable production knowledge on the part of the purchasing executive for the pipeline will enable him to bargain more effectively and, at the same time, more cooperatively, in the securing of the most economic gas purchase contracts.

* * *

"A pipeline's production department can encourage the useful development of reserves which are favorably situated in respect to its own system."

The Consolidated Group submitted that these advantages provide valuable benefits to the producing pipelines and their customers even though their value cannot always be precisely quantified.

The Consolidated Group contended that pipelines are required to compete with independent producers for the acquisition of

[10088]

leases and that pipelines and independents must deal with royalty owners on the same basis. In the final analysis, the price which a pipeline can afford to pay for a lease or royalty agreement is determined by the allowance the pipeline can expect for the gas it finds and produces. Unless the Commission applies the same rate-making treatment to pipeline production that is applied to production by others, pipelines will allegedly be at a distinct disadvantage in attempting to acquire new leases or bargaining with royalty owners.

Because the Supreme Court's *Permian* decision made it clear that the area approach was appropriate for regulating the price of gas sold in interstate commerce by independent producers, the Concolidated Group argued that the Com-

mission is legally free to depart from the cost-of-service method in determining the allowance for gas produced by pipelines from leases acquired in the future. The Supreme Court has long held that neither the Constitution nor the Natural Gas Act tie the Commission to any particular rate making formula. *Federal Power Commission v. Natural Gas Pipeline Company of America,* 315 U.S. 575 (1942); *Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 591 (1944). The Court observed in the second *Phillips* case (373 U.S. at 309):

> ". . . The Court has never held that the individual company cost-of-service method is a *sine qua non* of natural gas rate regulation."

Regulatory agencies have a wide range of discretion in selecting the most appropriate method of regulation and the Commission may "make the pragmatic adjustments which may be called for by the particular circumstances" (315 U.S. at 586). The controlling factor is "the result reached not the method employed" (320 U.S. at 602).

After going to great length in describing the advantages of pipeline gas production and the reasons for advocating area-rates for everybody else, the Consolidated Group submitted that this method is not feasible for the Appalachian Area.

The Consolidated Group submitted that in the Appalachian Area production is dominated by four pipeline distributor systems which provide the lead for thousands of small independent operators. Facilities operated by producing pipelines in the Appalachian Area perform multiple functions of gathering, transmission, storage and distribution. Appalachian production is

[10089]

allegedly peculiarly valuable both because of its geographical location in relation to Eastern load centers and because of the conversion of partially depleted gas fields to storage pools close to market areas. In view of these atypical pro-

duction circumstances and resultant atypical costs in the Appalachian Area, the Consolidated Group said, that application of "new gas" area prices based on current nationwide costs would be inappropriate in that area. Moreover, determination of a "new gas" price based on generalized Appalachian Area costs would be impractical because of nearly insuperable data gathering problems. For these reasons, the Consolidated Group urged that the cost-of-service method should be retained for Appalachian pipeline production.

Pipeline companies operating in the Appalachian Area tend to have higher success ratios than pipeline companies that operate in other areas. However, the exclusion of the Appalachian companies does not allegedly change the results shown in Exhibit 23 and 24. Since neither the affiliated nor independent producers have a significant portion of their operations in the Appalachian Area, the inclusion of the Appalachian data for these two groups supposedly has a negligible effect on the percentages shown.

The cost-of-service in the Appalachian Area has allegedly served a useful purpose in the past and the Consolidated Group urges that it be continued. Supply Company President Corrin testified:

> "In these circumstances, as a manager of a gas company to which the alternative would be applied, I have concluded that our Company can best serve its customers under a cost-of-service approach for its production in the Appalachian area. It has proved satisfactory in the past. I can find no valid basis for proposing a change."

There allegedly is nothing in the Natural Gas Act that would require the Commission to apply area pricing uniformly to each and every pricing area in the country. To the contrary, the Commission has wide discretion to make whatever pragmatic adjustments are necessary to accomplish the regulatory purpose. The Consolidated Group concluded that the only way the Commission can accomplish that objective in the Appalachian Area is to continue its present

policy of regulating pipeline production on a cost-of-service basis.

[10090]

It is noted that, as an interim measure, Staff recommended continuing cost-of-service for Phase I pipeline production until an Appalachian new gas area rate is established. In making this recommendation, Staff recognized that for at least some pipelines this may continue the application of allowed production rates significantly above the new gas national average cost levels (as would be the case using the in-line or guideline rates). In view of the history of high in-line and guideline rates for the area, its partial use for providing gas storage and its possible other differences from other producing areas (which relate to its location and high production costs), Staff did not recommend abandoning cost-of-service until an area rate is established. This would defer applying a group costing standard until the Commission will have had opportunity to consider in its rate determination such factors which may be special to the area. While the Staff recommend continuing cost-of-service pricing for gas production from newly acquired leases, Staff would limit such production rate allowance in future costs-of-service calculations to the applicable area in-line rates. In view of Commission regulation elsewhere Staff would view the placing of no limitation on the allowed price for Appalachian pipeline produced gas inequitable both with regard to the consumer and with regard to other producers.

E. *Tennessee*

Tennessee Gas Pipeline Co. (Tennessee) is a Division of Tenneco Inc. It owns and operates an extensive pipeline transmission system, and also produces some of the gas used to serve its customers. As of the end of 1966, Tennessee owned an estimated 1.5 trillion cubic feet of proved dry gas reserves, exclusive of the reserves acquired by it by the purchase of the reserves in place in the Bastian Bay and Ship Shoal Block 176 Fields.

[10090]

In general, Tennessee's arguments in favor of area rate treatment and against modified area rate treatment for pipeline-produced gas were similar to those advanced by the Pipeline Production Group. It is Tennessee's position that for rate making purposes, the Commission should treat natural gas produced by pipeline producers from leases acquired subsequent to the data of the Commission's order in this Phase I of the instant proceeding on the same basis as comparable gas produced by independent producers.

[10091]

Tennessee submitted that application of area rates to gas produced by pipeline producers will further the objectives of the Natural Gas Act. The anticipated future requirements for natural gas allegedly make it imperative that pipeline producers be encouraged, along with other potential producers to explore for, and develop new gas supplies. Task of finding gas supplies adequate to satisfy future requirements is tremendous. The Commission and the Supreme Court have recognized the need to provide an incentive to explore for new gas. Area rates should be applied to pipeline produced gas to encourage expanded future production activities. Area rates are needed to provide pipeline producers the same incentive as independent producers. Exploration and development is same for all producers. Considerations supporting area rates for independent producers equally applicable to other producers. Consumers will benefit from area rates for all producers.

Tennessee said that the several additional benefits available from pipeline ownership of, and production from, own reserves is further justification for applying area rates to gas produced by pipelines and affiliated producers. Improved bargaining position vis-a-vis independent producers. Ownership of reserves helps meet fluctuations in customer requirements.

Tennessee argued that at least since 1955, there has been a steady decline in the exploration and development activ-

ities of pipeline producers primarily as a result of the Commission's application of cost-of-service method in pricing gas produced by such producers. Several pipeline producers have virtually ceased all exploration and development activities since that time (Exhibit 28). And, while there has been an absolute increase of about 36 trillion cubic feet in proven natural gas reserve over the period covered from 1958 through 1966, there has been a major decline during that period in natural gas reserves owned by pipeline producers with large reserves.

Tennessee submitted that the natural gas reserves owned by the fourteen major pipeline producers declined by some 8 trillion cubic feet over the 1958-1966 period, or a decline of nearly 30 percent (Exhibit 30). In contrast, the total gas reserves committed to these pipeline producers increased by over 22 trillion cubic feet over the same period (Exhibit 31 as corrected). Gas production by pipeline producers increased by only 18 percent over the period from 1955 to 1962 as compared to a 68 percent increase in such production by independent producers. On the other hand, pipeline producers increased their oil production

[10092]

during the same period by some 122 percent while the oil production by independent producers increased by only 27 percent (Exhibit 32). In terms of marketed volumes, the pipeline producers' share of the total marketed volumes of all respondents decreased from 10.6 percent in 1955 to 7.8 percent in 1962 and their share of the total of all gas marketed in continental United States declined from 6.6 percent in 1955 to 5.2 percent in 1962 (Exhibit 33).

Tennessee contended that in light of the failure of cost-of-service to provide the requisite encouragement, the Commission should apply to pipeline production subject to this Phase I of the instant porceeding the same area rates as applied to gas produced by independent producers from leases in the same pricing area. This allegedly would pro-

[10092]

vide pipeline producers with the incentive to explore for and develop new gas reserves. In addition, this would enable them to realize the various advantages from pipeline ownership of gas reserves.

F. *Humble*

Humble Oil and Refining and Humble Gas Transmission (Humble) took the position that gas produced by pipeline companies or their affiliates should be given parity of treatment with gas produced by independent producers, including delivery condition and quality requirements, and that Humble Oil should be allowed to sell gas to Humble Transmission at the full area rate unmodified.

Humble claimed that the record failed to establish any differences with respect to technology, risk, or cost incurrence between the gas production of pipeline producers and independent producers. However, if pipeline producers are allowed the full area rate for their production, then parity also requires that they be subject to the same conditions of delivery and quality standards, as independent producers in order to avoid competitive advantage over independent producers.

Staff's proposed downward adjustment in the return component of the area rate because of a difference between the capital structure of pipeline companies and independent producers, Humble argued, is totally unjustified. The required return is determined by the business risk of finding and producing gas, not by the average of the risk of the regulated entity. Imputation of the capital structure of the less risky transmission function to the production function of pipelines can only discriminate against the production function, Humble contended. Assuming the

[10093]

adoption of Staff's proposed return modification, Humble Transmission would allegedly be entitled to the unmodified area rate since it has no debt in its capital structure.

At the present time, Humble Oil makes no jurisdictional sales to Humble Transmission, despite an alleged shortage of gas supply for Humble Transmission, because of claimed uncertainty as to the regulatory treatment which would be accorded such sales. Humble Oil requested that any sales to Humble Transmission in the future be permitted on the same terms as those applicable to sales to third parties.

[10094]

V. AREA RATE ADVOCATES–GROUP III AND IV PIPELINE AFFILIATES

The pipeline affiliates have vigorously contested Staff's recommendations as applied to them on the grounds that they are in fact independent producers and are operating as such. Such testimony was presented by witnesses for Cities Service Oil Company and Columbian Fuel Corporation (8(2)/810-894; 38(1)/4137-4167), Tenneco Oil Company (8(1)/723-729; 38(1)/4046-4052) and Union Producing Company (8(2)/747-768; 38(1)/4068-4092).

The Commission Staff submitted that some pipeline affiliates are no more than "producing arms" of their related pipeline companies, but that others may be functionally operating more like separate entities. Staff recommended that: (1) a pipeline affiliate which sold all of its production to nonrelated companies should be allowed the same price as a hypothetical similarly situated independent producer; and (2) a pipeline affiliate which sold all of its production to its related transmission company should be allowed the same price as a single corporate structure. This, Staff argued would give practical effect to the extent to which a producer and its affiliated pipeline company are operating in a functionally interrelated manner.

A. *Cities*

Cities Service Oil Co. (Cities) and Columbian Fuel Corp. (both merged effective July 1, 1968) argued that their rates for sales to Cities Service Gas Co. should be regulated in the

[10094]

same manner as the rates of independent producers. In support, the two companies stressed that they are operated and have been consistently treated by the Commission as independent producers. Moreover, they allegedly do not function as "producing arms" of Gas Co. In fact, only a very minor proportion of the business of Oil Co. and Columbian Fuel is transacted with Gas Co., *i.e.*, around 8.3 percent of their combined 1966 jurisdictional sales contracts cover sales to Gas Co. Also, the two affiliates noted, Oil Co.'s oil and gas exploration and production operations are spread throughout most of the United States, and not confined to areas served by Gas Co.'s system.

The Cities companies further alleged that the contracts of Oil Co. and Columbian Fuel with Gas Co. are no more favorable than those with unrelated parties dealing at arm's length. They pointed out that about 85 percent of Oil Co.'s sales and 100 percent of Columbian Fuel's sales to Gas Co. are made under contracts

[10095]

negotiated by nonaffiliated parties at arm's length. Of Oil Co.'s remaining sales to Gas Co., the contracts were said to have been executed on the same terms negotiated by nonaffiliated parties. Under these circumstances, it was submitted that application of independent producer regulatory methods to sales of the two Cities companies to their pipeline affiliate was fully justified and would satisfy the regulatory purpose of assuring reasonable and nondiscriminatory rates. If a price of given supply determined in an area rate proceeding is proper when charged by Oil Co. or Columbian Fuel to an unaffiliated buyer, Cities argued that price should also be proper when paid to them by Gas Co. The Cities companies submitted that under either Staff's preferred or alternative recommendation, the Oil Company and Columbian Fuel should receive the full independent producer rate for all of their jurisdictional sales of natural gas, including their on-system sales for any one or more of the following reasons:

The capital costs of the Oil Company and Columbian Fuel allegedly fall well within the range experienced by other independent producers. The Oil Company and Columbian Fuel are "off-system" affiliates. The parent company of the Oil Company, Columbian Fuel and the Gas Company is an independent producer, rather than a pipeline company, and the transmission function is allegedly subordinate to the predominate production function.

The traditional individual company cost-of-service method of price regulation is allegedly wholly inappropriate and impractical for the purpose of determining the proper prices for sales of natural gas by the Oil Company and Columbian Fuel to the Gas Company. Cities argued that: (1) the production activities of the Oil Company and Columbian Fuel are not utility in nature, are not integrated with the Gas Company's utility function and, therefore, should not be accorded utility type individual company cost-of-service treatment; and (2) the Oil Company and Columbian Fuel function as independent producers, not as producing arms of the Gas Company, and the Commission has allegedly found that such method is not sensible or even workable for regulating producers having such characteristics.

Since they allegedly have the same characteristics as other independent producers, prices for gas supplied by them to the Gas Company can and should be regulated through application of the same criteria as are sales by them and other independent producers to unrelated pipelines, thereby avoiding discrimination; and a full individual company cost-of-service rate procedure would be required to regulate only a fraction of the total deliveries by

[10096]

the Oil Company and Columbian Fuel which allegedly is not practical or warranted.

The Cities companies other reasons why the rate-base cost-of-service method is not an appropriate method for

determining the reasonableness of the prices for gas supplied by the Oil Company and Columbian Fuel to the Gas Company are allegedly supported by evidence in the record that they are independent producers in every respect and the rates for sales of natural gas by them to the Gas Company should be established in the same manner as that applied in establishing rates for sales of natural gas by them and other independent producers to unrelated pipeline companies.

The Commission had occasion to deal with Cities very similar contentions. In *Continental Oil Co.* and *Continental Gas Producing Co.*, ___FPC___ (Opinion 542, June 27, 1968) the Commission held:

> The underlying question presented in this docket is of course whether the seller of the gas to Gas Co., whether it be Continental or Continental Producing, should be permitted to charge filed contract rates to Gas Co., subject only to such restrictions as would be applicable under our policies to an independent producer, when, as we have held in Docket No. R164-9, Gas Co. must treat the sales in its cost of service as if the seller were still its affiliate. We have concluded that Continental should be permitted to secure the price available to all other independent producers not affiliated with Gas Co. or the Cities System. Continental, we may assume, *arguendo*, was just as aware as Cities that if, after the stock purchase, it were allowed to charge rates as an independent producer and Cities were permitted to include this entire amount in its cost of service, Gas Co.'s ratepayers were going to pay substantially more than what they could expect to pay if the Cities Producing stayed as an affiliate of Gas Co. But equal knowledge of the probable consequences of the transaction does not carry with it equal responsibility, or mean that the "equities" in allotting the burden of the transaction must or should be equally borne. For it was Gas Co. and its parent Cities, not Continental, which had an obligation to Gas Co.'s ratepayers to operate in a reasonably prudent manner

with respect to the operations of Gas Co. (Page 25 of slip opinion)

[10097]

The Examiner concludes that prior reference to those companies as "independent producers" is not determinative of their just and reasonable rates. The rates in the instant proceedings must be established on the basis of the total evidence and presentation made herein. The 10 percent area rate for Cities gas, detailed in another section of this decision, is a compromise position, which the Examiner finds adequate to meet the contentions raised by Cities companies in this proceedings.

B. *Tenneco*

Tenneco Oil Company (Tenneco) urged that it be permitted to receive the same price for gas sold to its affiliate, Tennessee Gas Pipeline, as received by other independent producers.

Tenneco stressed the diversified nature of its operations and the *de minimis* volume of its jurisdictional gas sales to Tennessee (only 2.47 percent of total gas sales in 1965). Tenneco said that its natural gas activities would increase if the Commission approves a recent request for transfer of Tennessee's gas production properties. Tenneco claimed that, as an integrated oil producer, its production operations are more comparable to those of independent producers than to those of pipeline producers or affiliates making primarily on-system sales. Therefore, the company concluded, establishment of any rate differential between Tenneco and nonaffiliated producers for sales to Tennessee would be unfair and discriminatory.

Tenneco contended that any differential between its rates and nonaffiliated seller rates to Tennessee would discriminate against Tenneco in the acquisition of leases and in other legitimate business ventures with other producers. It would also reduce Tenneco's pro rata share of expenses. In short,

[10097]

Tenneco alleged the overall impact of any rate differential would be to discourage affiliated producers from acquiring leases where the only economically feasible market is to an affiliated pipeline, and from dedicating uncommitted reserves to affiliated pipelines.

Tenneco took no position on the appropriate rate treatment for pipeline producers and affiliated producers selling primarily on-system. However, assuming adjusted area rates were applied to these groups, and exception would allegedly be justified for Tenneco in view of its diversified operations, comparability to independent producers, *de minimis* volume of sales to Tennessee and the "microscopic" impact on consumers of allowing an unadjusted

[10098]

area price.

The major import of Tenneco's exhibits in this proceeding was to show that its operations are more similar to those of an independent producer than to pipeline producers or to affiliates which produce gas primarily to serve the affiliates which produce gas primarily to serve the affiliated pipeline.

Exhibit 39, 40 and 42, submitted as part of Tenneco's direct case, differentiated Tenneco and Group 4, of which Tenneco comprises one of five companies, from Groups 1 and 3. Unlike Tenneco and Group 4, Groups 1 and 3 (the pipeline producers and pipeline affiliates sales are primarily on-system) have emphasized their natural gas activities, as shown by the net acres and cost transferred from nonproducing to producing in 1962, the net working interest of total producing leases for 1962, and the on-system/off-system disposition of natural gas of the various groups.

Upon rebuttal, Tenneco Witness Freitage submitted Exhibits 55 and 56 comparing Tenneco with other independent producers.

Exhibit 55 compares Tenneco and Group 4 with independent producers (Groups 1 and 3).

The studies allegedly show that Tenneco is similar to an independent producer. The nature of the operations of Tenneco are claimed to be those of a large integrated oil company. To the extent Tenneco engages in the sale of natural gas, Tennessee Gas is supposedly only another customer. Tenneco is separately staffed and operated, including a separate accounting department, and its management has an incentive compensation system based upon the profits of Tenneco. The fact that Tenneco is a subsidiary of Tenneco Corporation, which is wholly owned by Tenneco Inc. of which Tennessee Gas is a division, supposedly has little bearing on the issues in this case.

Tenneco takes issue with Staff Witness Bass and his Exhibits 5 and 54, which show that Tenneco is not comparable to independent producers with regard to the profitability of its operations. Tenneco argues that: (1) whether one company spends more dollars per dollar of revenue or receives less revenue for each dollar invested is not relevant to whether Tenneco's operations are comparable to an independent producer; (2) Staff Witness Bass did not include any data for nonrespondent independent producers, and no valid analogy can be made unless such comparability is shown; and (3) the period used by Mr. Bass for this comparative study was 1955-1962. Tenneco's first production operations commenced in

[10099]

1961, and, accordingly, the studies reflect only the first two years of operations, the first being the year in which high cost properties were transferred to Tenneco.

Tenneco cited the diversified nature of its operations with much emphasis on oil and its by-products as one such factor. The import of such comparative studies of Group 4 Respondents and independent producers with Group 1 and 3 Respondents, would allegedly also be relevant to show the unique independent producer orientation of Tenneco and Group 4.

Tenneco requested a determination that it may *continue* to price its natural gas sold to Tennessee Gas at the same price Tenneco charges for other sales subject to Commission jurisdiction, *i.e.*, at the same price other independent producers charge Tennessee Gas for the same quality gas.

C. *Union*

Union Producing Company (Union) asked that it be given the same area rates as other independent producers of gas. Union contended that its gas production activity is typical of other independent producers. Union said that its activities are unlike that of pipeline producers. In contrast to Union's aggressive exploration activities, the record shows that relatively minor exploration for gas reserves has been, and is being, undertaken by producing pipeline companies. Pipelines having their own production are allegedly not comparable to those of Union and other independent producers. They have no relevant relationship to the regulatory method reasonably applicable to it. Union is here allegedly misjoined and should be placed with the independent producers of whom its operations are typical. The record alledgedly warrants the discharge of Union from this proceeding, and its joinder with independent producers so that it may receive whatever rate regulatory treatment the Commission accords independent producers generally. Union's motion for severance is dealt with in separate section.

Union is engaged in exploration, development, and operation of oil and gas leases which it continuously purchases, explores, and develops and from which it produces and sells natural gas, condensate and crude oil. Union does not transport gas away from the area of its production, nor does it purchase any natural gas for resale. The FPC regulates Union's rates for sale of natural gas in interstate commerce for resale. Union's sales of oil, other related products and intrastate sales of natural gas are

[10100]

wholly outside the jurisdiction of the FPC. Union's parent, until April 1, 1968, was United Gas Corporation at which date its parent was merged into Pennzoil United, Inc. The parent owns all the capital stock and the outstanding indebtedness of Union and owns and operates natural gas distribution systems in Texas, Louisiana, and Mississippi. The parent company also owns all of the capital stock and the outstanding long-term indebtedness of United Gas Pipe Line Company (United).

On a prior occasion, when Union contended that it should be exempted from cost-of-service rule regulations, the Commission held:

> In excepting to the Examiner's reliance exclusively on cost-of-service evidence in considering its rates, and his refusal to consider certain field price and exonomic evidence, Union contends that our Opinion No. 338 and our Statemtnt of General Policy No. 61-1 contemplate that field price and economic data also be considered in fixing producer rates. In this connection Union contends that the Examiner erred in treating it as the producing arm of a pipeline company rather than an independent producer. We conclude that cost-of-service evidence was properly the basis for determining rates where, as here, the producer is the producing arm of a pipeline company. See Panhandle Eastern Pipe Line Company, 25 FPC 787, and Northern Natural Gas Company, 28 FPC 4. The status of Union Producing as the producing arm of a pipeline company is not in doubt. Union is the wholly owned producing subsidiary of United Gas Corporation, which also wholly owns the pipeline subsidiary, United Gas Pipe Line Company, to which Union sells over 80 percent of its gas production. In referring to Union in *Mississippi River Fuel Corporation v. F.P.C.*, 252 F.2d 619 (CADC), cert. denied, 355 U.S. 904, the court said "A 100 percent affiliate stands in the same position as does the intergrated producing arm of a pipeline company."

[10100]

Union Producing Company, 31 FPC 41, 43-44.

The above was unanimously upheld by the Commission on rehearing:

> In its application for rehearing Union continues to urge that it should be regulated entirely as an independent
>
> [10101]
>
> producer and that certain of the principles to be applied to its cost were improperly determined. On these matters Union has raised no arguments with respect to the facts or the law which were not fully considered by us in our Opinion No. 414 and there is no reason for modification of the opinion as to these matters.
>
> *Union Producing Company*, 31 FPC 503

In brief, as Union has attempted to do on prior occasions, it has sized up the gas pricing situation "in terms of its own self-interest rather than the total public interest requirements" which we must consider in this decision.

D. *Corporate Transactions*

The Examiner concurs with Staff's contention that by operating through separate corporations a company cannot change the essential nature of its ownership. The fact that a company is setting up a different corporate entity for one of its regulated functions cannot itself justify different regulatory treatment. *Western Distributing Company v. Public Service Commission of Kansas*, 285 U.S. 119, 123-125 (1932), *Mississippi River Fuel Corporation v. FPC*, 252 F.2d 619, 621-624 (CADC, 1957), certiorari denied, 355 U.S. 904 (1957). The purpose of regulation is to fulfill a public need; form cannot be exalted over substance to obscure operative facts. *United Gas Improvement Company v. Continental Oil Company*, 381 U.S. 392, 395-404 (1965).

When two companies have the same parent, the control of the parent is there. The fact that the parent entity may not

directly interfere in the transactions of a particular division does not mean that it cannot exercise ultimate control when it will either be beneficial to the overall corporate structure or is necessary in the interest of the particular division. Staff submits that in the case of Cities Service itself, while their witnesses state that the production and transmission divisions are kept separate, there is indication that the companies conduct joint processing of liquid extraction operations and joint use of research and development facilities. Joint control of affiliates tends to manifest itself in their reporting of their financial operations.

The Examiner would not allow pipeline affiliates an increased rate of return for their on-system sales on the basis of the testimony of the various witnesses who would support such a position. Union's Witness Dunn stated that Union has a

[10102]

"capitalization ratio of 20 percent debt and 80 percent equity (which) is comparable to independent producers generally." The witness did not elaborate that Union's common stock and debentures are wholly owned by United Gas Corporation, joint parent to both Union and United Gas Pipeline Company. Mr. Dunn did concede that "United Gas Corporation is the entity that goes to the public for money" and that "all of its assets would be utilized in making good any default on its bonds." The value of the parent's equity would clearly be affected by the earnings and prospects both of Union Producing Company and by its related pipeline company.

A similar situation presented itself with respect to Tenneco Oil Company, which, according to Witness Freitag, is "truly comparable to an independent producer." Tenneco Corporation, parent of Tenneco Oil Company, has approximately 28 percent long term debt, 2 percent preferred stock, and 70 percent equity. On a consolidated basis, Tenneco, Inc. owner of Tenneco Corporation, has approximately 69 per-

cent debt and 31 percent equity. Tennessee Gas Pipeline Company, a division of Tenneco, Inc. has long term debt of 53 percent, preferred stock of about 19 percent, and common equity of 30 percent.

Staff made a convincing argument that the salient fact was that the equity ownership of the parent derived the benefits of both transmission and production earnings in a manner similar to the benefits which they would receive under a single corporate structure.

The Examiner, however, does recognize that adhering to orthodox cost-of-service pricing without any modification, for producing pipelines, might lead to either excessive future off-system sales by these pipeline producers or to future "spinoffs" of their producing properties to affiliates or to independent producers, which could then sell at prices above those which would have been allowed under the existing regulations to individual producing pipelines. The solution to this problem is not a blanket area rate for all gas sold by affiliates to related transmission companies. Such a finding would effectively abandon the Commission's function to assure to consumers "the lowest possible reasonable rate consistent with the maintenance of adequate service***" *Atlantic Refining Company v. Public Service Commission of New York*, 360 U.S. 378, 388 (1959). Instead, the Examiner is proposing experimental remedial rates, to be kept under Commission surveillance. This matter is discussed in the last part of the decision.

[10103]

VI. PRODUCERS-INTERVENORS' POSITION

Shell Oil Co., Gulf Oil Corp. and Warren Petroleum Corp. (Shell *et al.*) took the position that any method employed by the Commission to regulate pipeline-owned or affiliated production should promote and encourage such production on an equal footing with that of independent producers. However, no competitive advantage or crutch should be af-

forded pipeline production vis-a-vis production of independent producers. Specifically, "rates determined by the Commission for pipeline production, whether on an area rate basis or some other basis, must in the final analysis . . . keep pipeline production in a position competitively equal but not superior to that of independent producers. The Commission must duly consider institutional characteristics of pipelines as compared to the characteristics of the producing industry in general. The institutional nature of pipelines and the typical pipeline affiliates as public utilities must be recognized. This distinction may suggest significant problems respecting regulation of pipeline-owned production."

The Producer intervenors did not "***foreclose that the Commission may evolve a method of regulation for pipeline production which may include savings provisions or special exceptions applicable in certain circumstances for certain pipelines. Even if a group-area method of regulation may be in general appropriate for pipeline production, this does not mean that the Commission should ignore any special circumstances which may exist. An integral part of a group regulatory method is a viable savings clause which permits exceptions."

Continental Oil Co., Texaco Inc., Pan American Petroleum Co., Mobile Oil Corp., and Amerada Petroleum Co. (Continental *et al.*) expressed an identical position to that of Shell *et al.*, except that they went on to describe some of the problems which might arise under parity pricing for pipeline production. These problems generally related to treatment of gas below pipeline quality and to the point and conditions of delivery. Continental *et al.* urged the Commission to focus on these procedural problems in order that a true parity of treatment with independent producers can be achieved in the regulation of pipeline and affiliate production.

[10104]

"The precise methodology necessary to achieve true equality between independent producers and pipelines competitively and otherwise has not been fully crystallized on this record. One pipeline witness has recommended that the pipeline's rate case be the vehicle to insure competitive equality (Frazier). Another pipeline witness recommended that where the producing department of a pipeline is producing gas for on-system consumption, a statement setting forth the same basic data as is normally set forth in an independent producer contract or rate schedule should be furnished to the Commission for review to insure that no competitive advantage is being obtained (Elmer)". Continental *et al.* urged the Commission to focus on these problems in order that a true parity of treatment with independent producers can be achieved in the regulation of pipeline and affiliate production.

In their reply brief, the Producer intervenors took issue with various references to the *Permian* decision contained in the briefs of other parties to this proceedings. They said that "*** all of the cases Staff cites in its Initial Brief at pp. 148-149 (as supporting its view that no tax is payable on production) involved pipeline producers. In contrast, the sole case where such a computation was attempted for an independent producer resulted in the finding of a positive tax. In any event, if one thing is clear from this record, it is that this proceeding should not be the one in which this thicket is explored and the various arguments and counter arguments with respect to positive and negative taxes resolved or findings made with respect to them."

[10105]

VII. MODIFIED AREA RATE PROPOSAL

The Commission's Staff recommended adoption of modified area rates for gas produced from pipeline-owned leases

acquired after the date of the Phase I Order. Staff contended that application of uniform area cost standards to future pipeline and pipeline affiliated production would both benefit the consumer and be fair to the producer. Application of an independent cost standard to pipeline produced gas should help control the high cost tendencies largely associated with recent pipeline reserve acquisitions. Application of an area rate standard to pipeline production costs would discourage circumvention of independent producer natural gas regulation through the purchase of developed or semi-developed properties at above area rate costs. Application of Staff's suggested production cost standard would allegedly be fair to the pipeline producer and to the consumers.

Staff submitted that there is no justification to raise the pipeline rate of return to provide additional inducement to develop higher levels of gas supply inventory. It has not been demonstrated that alleged intangible benefits of pipeline production result either in significant cost additions or in consumer benefits of a nature which would justify allowing pipeline producers an increased rate of return for the production function. Staff said, El Paso has not demonstrated that it is entitled to special rate consideration due to its alleged need to blend low-cost casinghead gas supplies with high cost gas-well gas. The rate of return allowance for pipeline production from future acquired reserves should not be raised merely because under cost-of-service regulation pipelines have had higher than average industry cost experience for their past production. The rate of return allowance for pipeline production from future acquired reserves should not be raised to subsidize increased production plant investment.

Staff would allow pipeline producers the same rate component for royalty payments which are allowed independent producers. In areas where independent producer area rates have not yet been established, Staff recommended basing pipeline production rates on the relevant in-line or guideline

[10105]

rates. Staff recommended application to pipelines of special non-cost price determinants which are applied to independ- or Btu adjustments be applied to pipeline production. Gathering costs related to pipeline production should be allowed only to the extent that such costs are not

[10106]

already in the area rate. The costing of pipeline processing costs in future pipeline cost-of-service determinations should be done consistently with the applicable liquid credit determination in area rate proceedings. Pipelines should be allowed that production tax in their cost-of-service which represents the taxes which must actually be paid to the state taxing authority under applicable state law. Casinghead gas should be priced consistently with the applicable area rate proceedings. Allowances for new gas production, based on modified area rates, should not be increased as a component in a pipeline's overall cost-of-service until further order of the Commission. Since all pipeline produced gas would presumably be imputed in pipeline costs-of-service at independent producer cost levels, there is no need for a minimum pipeline producer rate. Pipelines should be able to specially petition for exemptions from the determinations made herein. Sales by pipeline affiliates to related transmission companies should be regulated similarly to a pipeline's own production; sales by such affiliates to nonaffiliated purchasers should be regulated similarly to independent producer sales.

Staff submitted that Appalachian pipeline production should be continued to be costed on a cost-of-service basis (limited to the in-line ceiling) until the establishment of new gas area rate ceilings for that area. Staff presented its direct and rebuttal evidence in this proceeding through eight witnesses. Six of these witnesses dealt with operational and statistical matters related primarily to pipeline production and to some extent to independent producer production. One of the other two witnesses for the Staff, Dr. Shaffner,

presented testimony designed to assist in determining the rate of return and income tax treatment to be applied to pipeline produced gas. Mr. Deutsch presented a summary of the Staff case and its recommendations for Phase I of this proceeding.

The first four Staff witnesses, Messrs. Raymond, Beirne, Fell and Hubbard, presented evidence concerning income taxes, operational flexibility, prices and operating ratios.

Witness Bass presented both direct and rebuttal testimony on behalf of the Staff. On direct, he developed and compiled various operating ratios on a group basis to determine similarities and differences in the functional operations of producing pipelines, pipeline affiliates and other producers. On rebuttal, he sponsored Exhibit 54 wherein he set out the individual pipeline and

[10107]

pipeline affiliated company data underlying the composite data contained in his direct presentation.

Witness Zabel presented testimony and data relating to gas reserves and drilling statistics with respect to pipeline Groups I, II, III and IV. Most of the schedules presented by Mr. Zabel either do not include Group IV companies or contain information only with respect to "near-system" reserves and acreage. "Near-system" reserves and acreage were defined in part as being located within 25 miles of the affiliated pipeline system including laterals. Messrs. Shaffner and Deutsch relied upon certain of the data presented by Mr. Zabel to support their conclusions.

The purpose of Dr. Shaffner's testimony was to assist in determining the rate of return and income tax treatment for pipeline produced natural gas. He made no recommendation as to whether cost-of-service or area rate treatment should be used to regulate pipeline produced gas.

Mr. Deutsch presented a summary of the Staff's case and its recommendations as to Phase I of this proceeding. His

[10107]

recommendation was that with respect to natural gas produced from leases acquired by pipelines after the issuance of the Commission's order in Phase I, the Commission should adopt the policy of applying area rates to such production with the rate of return and Federal income tax modifications discussed by Dr. Shaffner in his testimony. Thus, the major exception to his recommendation for "area rates" is an adjustment in the rate of return component because pipelines, to date, have incurred more debt in their total capitalization than independent producers. Although Mr. Deutsch indicated that the Staff had directed its efforts toward group data in arriving at its recommendations, it expected individual companies to advise the record of special differences related to their operations.

In support of a "modified" return component, Staff argued that the claim of pipeline producers for an independent producer rate of return is no more than a request for a special rate allowance above their financing costs. Imputing the independent producer rate of return to pipeline production, Staff contended, would not serve the purpose of encouraging production efficiency. Rather, it would allow pipelines "to accomplish through the back door what they have not been able to do through all the years of regulation; to receive a price for their own production in derogation of cost standards."

[10108]

Staff submitted that evidence demonstrated that the cost of financing for pipeline producers was significantly less than for independent producers due to a greater use of debt by pipelines. The evidence allegedly indicated that pipeline debt issues were generally not restricted as to employment of funds so that low cost debt can be and was used to finance production operations. Staff pointed out there is no evidence that the cost of financing for pipelines with production operations is higher than for those without production operations. By reason of such factors as income

tax advantages associated with oil and gas production, diversification and integration of related company functions, investors appear to prefer transmission companies with either their own or affiliated production departments. As Staff Witness Shaffner testified, "integration of the production and transportation functions can be an element creating financial strength, not weakness."

> There are really two schools of thought as to what measures cost of common stock equity. One is what common stock capital earns and the other is what it can be obtained for from the investor, and as you know very well, and I mentioned yesterday, there are a group of common stocks which include Polaroid—and I could furnish you with the names of the balance if you wish—which show that they are selling at around 93 percent of earnings, which would make the investor willing to pay nearly $93 for one dollar of earnings. This would appear to indicate that the public has become more inflation conscious than it has in the past and that they are going into common stocks very heavily. (Tr. 1201, 1202)

Staff argued that the *Permian* opinions of both the FPC and the Supreme Court, specifically referred to the fact that the 12 percent rate of return adopted for independent producers was equivalent to the 10 percent to 12 percent yield on equity for pipelines at a 6 percent to 6.5 percent overall rate of return. However, whereas a 6.5 percent overall return on pipeline investment roughly equates to the equity return allowed independent producers in *Permian* (only about 1 to 1.5 percentage points higher than the overall return), an overall return of 12 percent for pipelines would yield equity returns of well over 20 percent and up to 40 percent in some cases.

[10109]

> *** I do not recommend either cost-of-service or area price treatment to regulate regulated pipeline produced gas. (Tr. 491)

> However, since pipelines have a great deal more leverage, have a great deal more debt, which costs less than equity, and even today it costs less than equity, this provides them with an advantage in their capital costs which independent producers do not have.
>
> I am simply pointing that out. (Dr. Shaffner Tr. 1061)

In answer to the Pipeline Group's contention that area rates should be applied to pipelines without discrimination, Staff argued that application of the rate of return reflected in area rates would not serve the same purpose of rewarding and encouraging pipeline production efficiency as application of the production costs reflected in area rates. Staff said that the lower capital costs for pipeline companies arising from greater debt financing in no way relates to production "efficiency" but rather relates to the overall nature of their operations. Staff submitted that the most important factor in rate of return has always been a company's actual capital cost. "Thus, if the Commission decides to consider other factors in determining rate of return, such determination should not be made under the guise of awarding 'parity' with independent producers when such 'parity' will result in equity rates of return far above 20 percent."

Staff rebutted claims that a higher rate of return on pipeline production operations was justified by the need to encourage exploration for and development of additional supplies and by various intangible benefits of pipeline production (*e.g.*, flexibility in takes, advantages in contracting with other producers and advantageously located reserves in relation to transmission lines).

Staff Witness Deutsch highlighted the findings of the other staff witnesses as follows:

*** however, the data [prepared by Witness Fell] seems to indicate that for

most of the areas involved, the nonproducing pipeline companies have lower average unit purchase gas costs than the producing companies. Thus, this would suggest that ownership of natural gas reserves, overall, did

[10110]

not enable producing pipelines to purchase gas from independent producers at lower prices than those paid by nonproducers. Or, alternatively, the producing pipelines did not seek to achieve this end *** (Tr. 594)

The exhibits and testimony of Witness Zabel concluded that:

> *** The data reveal that producing pipeline companies did not purchase gas under accounts 800-802 at prices consistently lower than nonproducing pipeline companies. Moreover the results indicate that there is no apparent advantage to pipeline companies even in individual pricing areas where they could claim the best advantages of production and purchase leverage. (Tr. 603)
>
> *** Staff Witness Raymond's analyses indicate an inconclusive correlation between reserves-production ownership and take-or-pay for positions of pipelines. Thus, the data do not establish, at least with respect to this factor, that reserves-production ownership is a cost-saving benefit to pipelines. (Tr. 604)
>
> *** I am able to conclude that early during this period the pipeline producing companies had been attaining greater flexibility from their own production than from their purchases. If the assumption is correct that flexibility had been a benefit or advantage, then the evidence indicates that the alleged benefit is diminishing. This would indicate either that pipelines with their own production are able to purchase flexibility as cheaply as or cheaper than operating their producing properties to achieve flexibility, or that other means of achieving flexibility are available at no greater cost.

[10110]

Q. Can you conclude whether company-owned production is a benefit? "A. No, I cannot. The available data, discussed up to this point in my testimony, fail to establish that operational or pricing benefits result from pipeline ownership of gas production." *** (Tr. 609)

[10111]

In his prepared rebuttal testimony, Staff Witness Bass said:

> ***When a comparison is made between the magnitudes of the possible cost increases and the possible cost savings resulting from pipelines "cutting back" on their production to avoid prepayment obligations, it appears that the advantage is not worth the cost. And, as I have previously stated, the avoidance of prepayment obligations is the only tangible advantage which the pipeline producers have shown to result from the use of their own production for increased flexibility. (Tr. 4114)

In conclusion, the Commission Staff would apply modified area rate treatment to all production by pipeline companies, whether used on-system or sold off-system, and to production by pipeline affiliates for on-system sales. Sales by affiliated producers to nonrelated pipelines would be allowed the full area rates applied to independent producers. This proposed treatment of affiliates, Staff said, rests on the extent to which they function as the "producing arm" of their related pipelines or as an independent producer.

Staff argued that application of industry cost standards to pipeline production, is consistent with the Commission's responsibility under the Natural Gas Act to protect consumers against excessive prices. Composited pipeline production cost data, allegedly demonstrate that cost-of-service pricing has led to pipeline purchases of developed and semi-developed properties at far higher costs than otherwise warranted. In addition, cost-of-service regulation appears to have encouraged an economically inefficient depletion of

pipeline-owned reserves. By comparison, "area rate costing methods create obvious incentives to efficient production." Staff said that application of area rate production costs to pipeline production would benefit consumers by placing a ceiling on the rates allowed for high cost gas and at the same time would give pipelines incentive to expand low cost production. "Given relatively assured return opportunities from their transmission operations, plus a typically high proportion of debt financing, pipelines should be provided with a particularly effective production stimulus by the opportunity to earn increased returns under area rate pricing."

Staff anticipated that the alleged benefits of area cost standards will be means of controlling high cost tendencies of pipeline production stemming from purchases of developed and

semi-developed leases. Apart from other difficulties, Staff added, such purchases "manifestly allow circumvention of Commission price regulation." The area rate, Staff stressed, covers the total estimated current cost of finding and producing gas, including the cost of new properties acquired by the producing industry. Thus, while these properties may be later transferred between the various parties, the area rate includes an element of cost to compensate for possibly higher initial returns or other costs borne by independent producers and associated with their sales of developed properties. Noting testimony of pipeline witnesses that the purchase of developed reserves is really a "transfer operation" which does not increase supply but rather is a substitute for purchases under conventional contracts, Staff urged that this change in the form of reserve purchase should not be permitted to circumvent the area rate. "The fact that companies may choose to split up the various producing functions among themselves should not be reason to charge consumers more for the total function."

[10112]

Staff contended the fact that a pipeline may use its production in various ways to the benefit of its transmission function, while an advantage, does not justify a higher price. Referring particularly to the claimed advantage of "flexibility," Staff said that with present day pipeline operations at increasingly higher annual load factors, the need for company-owned production—providing swing capability exceeding that available under producer contracts—has diminished. Furthermore, if producer sales in the future should not allow sufficient flexibility to meet pipeline needs, then the solution is not to subsidize a transfer of costs to the pipeline but to control the producer practices. In this connection Staff noted that the Commission has already prescribed certain daily contract quantity and make-up provisions in future contracts which might be detrimental to natural gas consumers, thereby limiting the potential harm which flexibility is supposed to mitigate.

In regard to Federal income taxes, Staff recommended that no tax component be computed for purposes of pricing pipeline and pipeline-affiliate production but that overall company tax expense be included as part of each pipeline's transmission cost-of-service. While aware that the production function may generate substantial tax losses, Staff said its position was fully consistent with the long-established ratemaking principle limiting cost-of-service to expenses actually incurred. The respondents' claim that any tax savings from production operations should be treated as an incentive for exploration and not

[10113]

applied as an offset against transmission tax liability for ratemaking purposes, is allegedly no more than a claim for an additional return. The adoption of a different method of regulation for pipeline-produced gas, Staff contended, is no reason to overrule the "actual taxes paid" doctrine developed by the Commission for the benefit of consumers merely to give respondents the possibility of an additional rate allowance regardless of cost.

Staff calculations showed that the effect of adjusting the Commission's current cost determination in the *Permian* case to include a 6.5 percent instead of a 12 percent rate of return (with related adjustments for production taxes but not for royalty payments) would be to reduce the new gas cost from 16.43¢ to 13.68¢.

[10114]

VII. OPPONENTS TO MODIFIED AREA RATES

With the exception of California all parties to this proceeding attacked Staff's modified area rate approach as discriminatory and unduly burdensome.

California rejected both the traditional cost-of-service method and the area rate method for determining rates for pipeline-produced gas, and instead supported the modified area rate method proposed by the FPC Staff. This choice, California said, involves lesser risk to the consumer by setting a ceiling on the cost of gas. Yet, at the same time, it takes into account the realities of pipeline capital structures as compared with those of independent producers and maintains the present "actual tax" treatment of pipeline companies. However, California expressed concern over the use of the modified area rate. California urged that care be taken to assure that the modified area method avoids double counting on such items as quality-raising costs, gathering costs, plant liquid revenues, etc. Furthermore, California submitted that provisions for relief should not be so general as to permit exemptions on a mere showing of costs exceeding the modified area rate.

A. *Municipal Group*

The Municipal Group submitted that Staff's modified area rate proposal would create serious administrative problems not present under cost-of-service regulation. They argued that if an area rate case were settled by the participants and accepted by the Commission, there would be no basis for

[10114]

calculating Staff's modified area rates to determine the proper rate for pipeline produced gas under Staff's theory. Settlements traditionally refer only to the ultimate cents per Mcf price agreed to by the parties. Settlement prices thus have no direct relationship to a breakdown between the actual costs and actual rate of return that would be adjudicated upon a full decision on the merits. Accordingly, it would be impossible to determine from the settlement price just what portion thereof is properly related to costs and return items. Without the determination

[10115]

of the cost and return items for the area rate, it would be impossible to apply the Staff's modified area rate proposal for pipeline produced gas to determine the proper rate to be charged for such gas in individual pipeline company rate cases.

It would be no solution for the parties to an area rate case settlement to attempt to state cost and return figures in the settlement. Since such figures would have no basis in any adjudication by the Commission of actual costs and return and probably no internal relationship to the final settlement figure itself, any such attempt would produce only arbitrary figures having no relationship to any standard established under the Natural Gas Act. The Municipal Group conceded that the Commission may decide to accept only few settlements of area rate cases, however, the Municipal Group argued that the Commission should not want to adopt an administrative policy for pipeline produced gas that would effectively preclude the settling of such cases in the future under appropriate circumstances.

Witness Smith testified that the Staff proposal in this case for solving the accounting problem would burden consumers. He emphasized that the area rate proposals in this case were incompatible with retention of the principles of matching costs and revenues in the Uniform System of Accounts. He pointed out that accounting for gathering costs and

liquids credit will pose serious problems under Staff's proposed regulatory theory.

The Municipal Group said that under the Staff's proposed new method of regulation, difficult allocations of the general and administrative expenses of the pipelines would have to be made in the individual pipeline rate cases. Determination of the proper amounts of these expenses to be charged to the transmission operations and thus paid by the ratepayers as against the portion charged to production and thus to be reimbursed by the proposed area rate allowance will allegedly pose highly contested issues. The Municipal Group contended that Staff's method will open the door to a situation for which adequate regulatory controls would be impossible to devise. For example, suppose that a pipeline company decides

[10116]

to devote the major part of the time of its President and other administrative personnel to the production operations of the company, even though these operations produced only a small portion of the total revenues of the company. If these expenses were allocated solely on the basis of overall revenues between production and transmission operations then clearly the ratepayers would be subsidizing the production operations of the company. The Staff's proposal would allegedly require the Commission to embark on a whole new scheme of regulatory devices if the consumers are to be adequately protected.

The Municipal Group argued convincingly that Staff's new regulatory proposal for pipeline produced gas will entail no regulatory time savings. Individual rate cases will continue to be required for each company. Applying area rate valuation to pipeline produced gas would actually have the effect of converting a substantial portion of the pipeline company's operations from utility to nonutility status. The complex allocation issues would delay, not expedite, the rate cases.

[10116]

B. *El Paso*

El Paso said that in regard to the modified area rate proposal, Staff conceded some fairly substantial differences between the production operations of pipelines and independent producers in the past but contended there would be no essential differences between such operations in the future under modified area rates. However, El Paso argued, the record demonstrates that pipelines have always operated their production activities locally with reference to their systems rather than nationally. The record allegedly shows that costs and many other aspects of pipeline and independent producer production operations are totally different. Hence, El Paso argued there is no valid support for Staff's contention that pipelines will abandon their historic pattern of operations if granted modified area rates.

[10117]

C. *Pipeline Group*

The Pipeline Group disputed Staff's proposed adjustments of the area rate to reflect lower production taxes and for spillover of income tax benefits attributable to the production function so as to reduce the tax liability of the transmission function. The production tax adjustment should be rejected, the Pipeline Group said, since the record allegedly establishes that pipeline producers will nearly always be required to pay production taxes on the same basis as independent producers. As to the tax question, the Pipeline Group argued that depriving pipeline producers of tax loss deductions has no support in view of the continued enjoyment of such benefits by independent producers. The Pipeline Group contended that any advantages for pipeline producers derived from lesser financing costs are offset by other components of the area rate. The Pipeline Group argued that the evidence shows that the liquid credit available to pipelines from the sale of extracted liquids is substantially lower than that available to independent producers (0.89¢ in contrast to 3.84¢) and that this differ-

ence would allegedly reduce the pipeline producer rate of return to 5.79% at the 16.46¢ area rate recommended by Staff in AR64-1 and AR64-2. "The Commission could not in fairness adjust one component of the area price to reflect lower pipeline cost . . . without making other adjustments to reflect higher pipeline cost."

The Pipeline Group said that even assuming a difference in financing cost between pipeline producers and independent producers in the past, this difference is currently shrinking and hence eliminates any possible justification for a discount from the area rate. The Group cited evidence indicating incremental financing over the 1962-1966 period of 35% debt and preferred stock capital by independent producers compared with 55% by pipeline producers. These incremental percentages, the Pipeline Group said, suggest increased reliance on debt financing by independent producers and a thickening of pipeline producer equity in the future. Most pipeline producers, the Pipeline Group submitted, no longer have highly leveraged capital structures but typically have equity ratios of about

50%. Therefore, Staff's rationale for isolating pipeline producers for separate rate of return treatment—to avoid an excessive rate of return resulting from a highly leveraged capital structure—is simply inapplicable to most pipeline producers.

D. *Consolidated*

Consolidated argued that the application of area rates to pipeline producers on average would not result in the return on equity predicted by Staff. Consolidated submitted that if we take into account the fact that we are in Phase I considering the allowance for *future* production and, accordingly, adjust the above calculation for the higher cost of debt now experienced by pipelines since 1962, the return on equity would be considerably less than the return anticipated by Staff.

[10118]

Consolidated submitted that pipelines with a relatively high degree of production investment rely heavily on equity financing and do not, as the Staff implies, use great proportions of debt in their capital structures.

E. *Tennessee*

Tennessee contended that the Staff's proposed individually tailored rate of return is contrary to, and in violation of, the basic concepts underlying area rates. Individualized rates of return for pipeline producers are allegedly not justified by the variations in return requirements among these producers. Not only do rate of return requirements similarly vary among independent producers, but the Commission's *Permian* decision expressly took cognizance of these variations in independent producers' return requirements, and concluded in view thereof, that the allowance of a uniform rate of return would help provide the incentive intended by area rates.

Tennessee took issue with the Staff's contention that financing of production by pipelines is less expensive than financing of such production by independent producers. The Staff's arguments allegedly overlooked, (1) that the rate of return allowed the production phase of a mixed company may not properly be reduced because of the company's other activities and should be based solely upon the risks associated with the

[10119]

production phase of the company's business; (2) that even though only one overall rate of return can be determined for the totality of a mixed company, such overall return should itself properly be a blend, reflecting the differing rates of return for the various risk levels of the company's diverse activities—not the minimum level associated with the company's lowest risk activity; and (3) that whatever might have been the capital costs of pipelines vis-a-vis independent producers in the past, independent producers may

well be able to finance future production activities cheaper than pipeline producers.

Tennessee challenged the Staff's contention that the risks associated with pipeline production are less than those of independent producers. Tennessee claimed that the risks associated with exploration and development of new gas reserves are the same regardless of whether undertaken by a pipeline producer, an affiliated producer, or an independent producer.

F. *Union*

Union charged that Staff's modified area rate proposal would be discriminatory and unfair to producers such as Union and would effectively preclude future exploration and production activities. Moreover, Union asserted, Staff's proposed treatment of rate of return and federal income taxes on an individual pipeline company basis would not be workable since these items are interrelated with every item of expense and revenue for each individual company. Staff's proposed method, Union said, is not to compute an individual company return by applying the individual company rate of return to the individual company rate base, but rather to compute return by applying the individual company rate of return to an imputed hypothetical rate base based on the Commission's determination of national average DD&A charges times 11 years. "Such computation bears not even a remote resemblance to individual company return computed at the individual company rate of return." Similarly, Union added, Staff's proposed tax calculations would bear no resemblance to any company's actual income tax liability which is based on individual company tax deductions related to return on individual company rate base. Thus, Union concluded, Staff's

[10120]

proposal would require separate rate determinations and separate tax determinations based on (1) area rates, and (2) individual company cost-of-service and actual tax deductions.

This "would create extensive, confusing and unworkable administrative problems . . . ."

Union also stressed that continued production of a wasting asset, *e.g.*, natural gas, requires a higher rate of return than for maintenance of a nonwasting asset, *e.g.*, a pipeline. However, Staff's proposal not only ignores the fact that production of gas consumes and exhausts a wasting asset which must be replaced, but would also serve to bring about the liquidation of production operations. In this connection Union cited its experience over the 1954-1965 period of plowing back 1-2/3 times its DD&A items into replenishment of reserves. It then calculated that under the Commission's new gas computations in *Permian*, including a 12% overall rate of return without modification, producers would receive only 6.3% on common equity after taking into account the replenishment of wasting natural gas. (This computation assumed plowback of 1-2/3 times DD&A of 3.95¢ or 6.60¢, to replace production. Deduction of 6.60¢ from the combined return and DD&A allowances of 9.51¢ left 2.91¢ for return on invested capital of 46.33¢, or 6.3%). Union submitted that assuming an overall rate of return of 6.5% under Staff's modified area proposal, producing operations would incur a cash deficiency of 1.18¢ based on a 1-2/3 times plowback of DD&A. (DD&A of 3.95¢ plus equity cash return of 1.47¢ yields total available cash of 5.42¢ or 1.18¢ less than 6.60¢). Union concluded that Staff's proposed modification of rate of return—based on the assumption that production of a wasting asset can be less expensively financed by using the relatively high debt ratios and fixed capital costs applicable to pipeline producer companies—is totally fallacious. "Such financing for producers, instead of being geared to the needs of the company involved, as claimed by Staff, is directly contrary to the needs of a company involved in substantial production operations."

[10121]

G. *Additional Problems*

In suggesting modified area rates for future gas production, the Staff offered two regulatory approaches for the Commission to consider regarding affiliates' sales. Staff's stated preference emphasizes that regulation of price should be according to type of sale, i. e. on-system or off-system, for gas produced and sold by affiliates of pipeline companies. Staff wants an affiliate, to the extent it makes on-system sales to its pipeline parent or another affiliate, to receive the modified area rates for such gas produced and sold (without quality or BTU adjustments) while off-system sales by the same affiliate should be allowed the full area or in-line rate (inclusive of quality and BTU adjustments) as received by the independent producers. Staff's alternate approach would have the commission classify all affiliates as either "on-system affiliates" or "off-system affiliates". Those classified as an "on-system affiliate" would be allowed to receive area rates adjusted to reflect an overall corporate rate of return for all of its gas produced and sold, while an affiliate obtaining a classification of "off-system affiliate" would be allowed for all of its sales the full area rates of independent producers, though these rates might be subject to some adjustment for the elimination of quality deduction on on-system sales.

The Examiner believes that the adoption of either Staff approach would have created more problems for the affiliates and the Commission than would have been solved.

An example of the creation of a problem can be demonstrated with the adoption of either approach as related to two affiliates, one in Group 3, Union Producing Company and the other in Group 4, Tenneco Oil Company.

Discussing Tenneco Oil Company first, and applying the Staff's preferred approach to it, Tenneco would receive modified area rates for its gas sold on-system and full area or in-line rates for its gas sold off-system. (Init. Brief of

[10121]

Tenneco Oil, p. 3). Tenneco, in 1965 produced 115,720,-000 Mcf of natural gas of which 2,861,000 Mcf, or 2.47% was sold to Tennessee Gas Pipeline Company. (Vol. 7, Tr. 399). Tenneco is now receiving full independent producer price for these sales to Tennessee Gas Pipeline (Init. Brief

[10122]

of Tenneco Oil p. 18). Of the total revenue received by Tenneco Oil from all sources in the year 1965, only 4.6% resulted from sales of natural gas, and *only 0.18¢* (less than 1/5 of 1%) resulted from these on-system sales of natural gas to Tennessee Gas Pipeline. (Vol. 7, Tr. 400). Here is a *de minimis* on-system sales situation which Staff would nevertheless require that modified area rates be charged by Tenneco Oil to its parent affiliate pipeline. Enough has already been said about administrative, accounting, reporting and other problems involved in converting to modified area rates for even a pipeline producer, to discourage completely the idea of requiring this Group 4 affiliate, largely an oil company, to develop modified area rates for its *de minimis* on-system sales. The requirement would be simply unreasonable under these circumstances.

The alternate Staff approach would classify all affiliates either "on-system" or "off-system" affiliates, and Union Producing Company apparently would be classified an "on-system" affiliate under this approach, though Staff does not provide the criteria for deciding which, how or why each affiliate will be regulated as either "on-system" or "off-system" affiliates. Staff said on pages 218 and 219 of its Initial Brief regarding how it would treat on-system affiliate sales in accordance with its classification:

> All sales made by the on-system affiliates, whether to related corporate entities or not, would have their applicable rate of return dependent upon their over-all corporate rate of return and all sales by the off-system affiliates would receive the area rate (presumably adjusted for the elimination of quality deductions on on-system sales). Since the rate of re-

turn adjustment for pipeline affiliate sales, as with pipeline sales, is principally due to affiliate's reduced financing costs, this financing advantage, where it occurs, would be equally applicable to sales to others as to sales to a related transmission company.

[10123]

The foregoing would indicate an affiliate classified an "on-system affiliate" would make all sales, on-system and off-system, at presumably area prices reduced by the difference between the area rate of return and the overall corporate rate of return. No mention is made by Staff of a further adjustment to the area rate to reflect the affiliates "actual taxes payable", but it appears that Staff is prescribing its modified area rate method for all affiliates' sales both on and off-system.[1] Thus Union would be required to reduce its rates for off-system sales, which are now made at full area or in-line prices, to conform with Staff's proposed modified area rates. Union's off-system sales are roughly 25 to 30% of its total natural gas sales, so under this alternate Staff formula Union's revenues would be substantially lessened. It is doubtful that such was the intended result.

IX. CONCLUSIONS

A. *Opening Statement*

Heretofore the Commission has practically always been regulating the prices of jurisdictional gas produced by pipelines and pipeline affiliates in accordance with the cost-of-service method. Traditionally, regulators have paid verbal

[1] Under this method Staff intends, that rather than adjusting the area rate, for the spillover of any tax deduction benefits from production to be applied as a reduction of tax allowance calculated for the transmission and other utility functions as part of the cost-of-service.

[10123]

homage to the solid, reliable and immutable cost-of-service approach. Reviewing courts have admonished the regulators that this sacrosanct approach must not be tampered with—certainly not more than is absolutely necessary. Where true hardship and competitive problems were properly demonstrated, the Commission has permitted in certain instances settlement deviations, in order to achieve practical solutions. This was done under the *de minimis* approach. *(De minimis non curat lex*—the law does not notice trifling matters). The recent area rates approach of pricing independent producers' gas was the catalyst, which touched off the instant proceedings. It is a forum where methods must be established for pricing future reserves of pipeline produced gas. The rules must be of manageable proportions, they must balance competitive interests,

[10124]

and also must be in accordance with the consumer oriented Natural Gas Act.[1]

The parties herein demonstrated to the Examiner that the present regulatory method of cost-of-service for gas produced by pipelines and of area rates for gas produced by independent producers causes a disequilibrium in rates for future reserves of jurisdictional gas. It would be desirable to continue with the fundamentals of pricing jurisdictional gas under the court tested cost-of-service method, but for the new problems encountered by the pipelines and their affiliates. The Municipal Group made an eloquent appeal urging to maintain intact the old system of regulation and its time tested components. They hoped that competitive problems would somehow vanish. However, we must face realistically the newly developed competitive facts of life in the FPC regulatory field. In the past half dozen years, we had few truly contested rate cases for jurisdictional gas produced by

[1] *Atlantic Refining Company* v *PSC of N. Y.* (360 U.S. 378, 388 (1959)

pipelines or their affiliates. Many cases have been settled—compromised, and possibly not always in the best interest of the gas consumer. Transfers of gas producing properties to affiliate producers raised problems in many instances (*Continental Oil Co.* and *Continental Gas Producing Co.*, Docket No. G-2737; *Cities Service Gas Co.*, Docket No. RP64-9; and *Tennessee Gas Pipeline Co. et al.* Docket No. CP66-269). The advent of area rates for independent producers which is to eventually encompass most of the Continental United States is creating diverse economic and competitive factors which will influence the supply and demand of new jurisdictional gas. This makes it very difficult to maintain the rigid cost-of-service regulation indefinitely. However, a gas rate increase must not be brought about prematurely. The record herein contains evidence to warrant only an interim balancing of equities, rate changes of only minor proportions. The Staff witnesses have effectively demonstrated that for the time being pipelines are still in a favorable money raising position and are also likely to secure tax benefits from production which would produce a windfall to the producers at the expense of the gas ratepayers. Over recent years, the cost-of-service method of regulation has undergone some deviations and exceptions. Rate cases have been settled flexibly. Large volumes of gas produced by pipeline affiliates have been exempted from cost-of-service and made subject to field prices under the *di minimis* clause (Tennessee Gas and others).

---

[1] *City of Detroit* v *F.P.C.*, 230 F.2d 810 (CADC), *certiori* denied 352 U.S. 829.

[10125]

The parties asking higher rates have failed to supply specific evidence sufficient to meet the standards of the *City of Detroit* case.[1] "*** that the rate increase is in fact needed and is no more than is needed, for the purpose . . ." However, the aggregate of the evidence presented in these proceedings persuaded the Examiner that, while a full area

rate for new gas produced by pipelines is excessive, the orthodox cost-of-service method no longer copes with the increased competitive aspects created by independent producers operating under area rates for new gas. The Modified Area Rates proposed by the Staff are likely to cause undue administrative burdens and are opposed to by practically all respondents. Under these circumstances, the Examiner is rejecting (a) the strictly orthodox cost-of-service method urged by El Paso and the Municipal Group, (b) the straight area rate advocated by most pipelines and pipeline affiliates, and (c) the Modified Area Rates proposed by the Staff. Instead, and until additional applicable evidence including some competitive experience is accumulated to meet the standards set in the *City of Detroit* case, the Examiner favors interim experimental minor modifications to the currently prevailing FPC methods of setting rates for gas produced by pipelines and pipeline affiliates. This modification does not abandon FPC's present well-functioning rate regulations, but merely augments it. Frankly, this is a practical attempt to face realities, to balance equities, to get out from an impasse, a decision to give the respondents an interim opportunity to meet increased competition from independent producers, without doing much injustice to the public interest. The reasons for arriving at these conclusions are outlined in the next sections, and the applicable mechanics are detailed in the last two sections of these findings.

B. *Discussion*

An important question about the determination of how pipeline produced new gas should be priced is whether pipeline production should be encouraged and if so, by how much. This is a matter upon which the Pipeline Group advanced considerable contentions, but insufficient evidence. The Examiner finds that encouraging an increase in pipeline production can be of value to gas consumers if an adequate pricing system were available to insure

[10126]

that the pipelines do not charge too high a price for this privilege. Pipelines can and do control the production acreage, from which they obtain some portion of their gas supply. This provides them with needed flexibility. There is also value in having pipelines engaged in gas exploration and development whose existence is dependent upon a supply of reasonably priced gas, as a counterweight to the independent producers' activities. The latter frequently are also engaged in the oil business which provides a competing fuel; they are interested in getting their money out of productive property in as short a period of time as possible, and are ever willing to divert major gas supplies to non-jurisdictional markets if they can secure a better price. The problem is not whether pipeline production should be encouraged, but how much should it be encouraged, so that it will best benefit the pipelines, but not place an unnecessary added burden on the consumers.

Currently pipeline gas production is regulated as to price on an individual company cost-of-service basis whereas independent producers have been partially regulated on a *de facto* area basis perhaps since 1954. The *Permian Basin* and *South Louisiana Area Rate Cases*, in which the Commission entered decisions, pertain to 43 percent of total 1962 production sales to pipelines. The recent Examiners' decisions in the *Hugoton-Anadarko* and *Texas Gulf Coast Areas* cover another 36 percent of 1962 jurisdictional sales to pipelines. The currently pending Other Southwest Area covers 14% more–a total of 93%. The figures from the Commission's all-areas questionnaire which have been introduced in the case indicate that pipeline production has increased nationally during the period 1955 to 1962. It was down slightly from 1961 and 1960, but in essence the production had been on a plateau between 1959 and 1962. Pipeline capital expenditures for their production departments also appear to have increased somewhat during the 1955 to 1962 period and pipeline exploration and development investment seems

[10126]

to have at least doubled over the period. The equivalent exploration and development investment figure for producers has gone up at a much slower rate. Pipeline costs and expenses for exploration and development operations have gone up percentagewise somewhat more than those for independent producers.

In general, in the past pipeline production, under individual company cost-of-service pricing regulations, has prospered. Since 1962 the Cities Service Company and Northern Natural Gas Company have sold their production affiliates to independent producers. The Commission's decisions in the *El Paso*

[10127]

and *Southern Natural* rate cases in October 1962, 28 FPC 688, and February 1963, 29 FPC 323, refused to grant any additional rate of return to the pipelines for their production activities. This may have discouraged subsequent exploration and development activities by the pipelines.

There are two types of pipeline producers, "low cost" and "high cost," The former are those who have been in the production actively for many years and have large reserves secured at very low prices prior to World War II, primarily in the Hugoton-Anadarko areas. The latter group includes all other pipeline producers. The diveragence is sharp. Individual pipeline rate cases have fixed per Mcf costs for some pipelines below independent producer averages, for others considerably above it.

Historical costing methods, which roll in new and old production expenses distort the almost certain fact that pipeline produced new gas for all companies–including those with much "cheap" old gas–is about as costly as average independent production. Figures introduced at the hearing show that pipeline production was in specific instances more expensive on a historical basis. But the differential may result in large part from the fact that pipelines seem to produce their leases at a slower pace, which in-

creases unit costs. The high price of some pipeline gas also represent expensive purchases of fully or partly developed leases. If we assume that future pipeline production will be "cheaper" than independent producer production—then putting them on such an area rate basis might encourage pipeline production. As was discussed before, this was not sufficiently supported by the record herein.

The advantage of an area rate to the pipeline is in giving it a degree of certainty that it does not now have and in avoiding a situation in which because of price differentials the pipelines may be inclined to sell gas off system or spin off production property to affiliated companies. If pipeline owned gas automatically gets the area ceiling price, it was argued that pipelines would be getting a better profit ratio than independent producers, and it may become difficult to hold the area rate for the latter to a ceiling rather than a uniform rate. If, on the other hand, pipelines are given not the independent producer area rate, but a rate based on the weighted

[10128]

average in-line price being paid in the area to independent producers, operating below an area ceiling, this may induce pipelines to contract at the area rate in order to increase their own rates.

Under cost-of-service regulation for pricing pipeline production, the principal items of tax savings related to production activities (depletion allowances and intangible well drilling benefits) not only serve to reduce the over-all taxes paid by the pipeline in the first instance but also benefit consumers as part of the pipeline's rates. However, when pipeline production is price on an area basis these tax savings are available to the pipelines to reduce taxes paid, but are not likewise available to reduce the cost-of-service, so consumer rates are not benefited.

There are wide disparities in pipeline production costs with respect to their gas leases. If it were decided to make

[10128]

it optional whether pipelines should go on area rates or remain on cost-of-service pricing with respect to "new gas," those who can obtain "cheap new gas" will promptly do so—those who must obtain "expensive new gas" will not. This would hurt the consumers both ways. If pipelines are put on a compulsory area rate for the future, some will reap windfalls. Others might experience substantial losses. The latter will claim that any such action is improper as to them. See prior summation of El Paso's and Consolidated Gas' presentations. Independent producer rates have never been fixed on an individual company cost-of-service basis (except for a brief period with respect to a few rate increase situations) so they cannot argue as in the case of the pipelines that they were induced to spend their money under one pricing technique only to have signals changed in midstream. Furthermore, producer losses may affect the individual producer's ability and willingness to engage in subsequent exploration and development—a private activity, whereas pipeline losses could affect their ability to perform their basic transportation functions—a public duty.

There are many production and management aspects which are equally applicable to the pipelines and to the independent producers of new gas. In many other respects, there is a marked competitive difference between the new gas ventures of the parties. Pipelines have a captive market. Their consumers underwrite all justifiable expenses. In the past, pipelines could raise venture money more readily and more economically

[10129]

than some independent producers. This financing situation is likely to continue. In general, pipelines developing new gas reserves assume less risk than independent producers.

It is in the public interest that pipelines continue to produce new gas at about the same level of participation in the overall gas production field as they have heretofore held. If the pipelines' production of new gas is priced at a straight

cost-of-service level, there are notable indications that such pipeline production might be reduced. This might diminish the operational flexibility and other leverage advantages, which thus far pipelines have used for their own benefit as well as for their gas customers. Some regulatory price relief is in order, otherwise pipeline production might diminish unduly. On the other hand, a straight area rate for pipeline produced gas is likely to be more profitable than the same straight area rate for independent producers; it would also tend to unduly increase the cost of gas to their customers, and it would not benefit the public at large. While pipelines can produce new gas for about the same cost as the independent producers, they fail to rebut effectively the contentions of the Staff and the Municipal Group, that area rates would yield pipelines excessive profits and at the same time would eventually tend to unduly raise the cost of gas to the public. The Commission must secure for the customers the lowest just and fair gas rates consistent with adequate service *Atlantic Refining Co.* v *Public Service Commission of New York*, 360 U.S. 378, 388-389 (1958). The central issue before us is not the selection of one gas costing regulatory method over another, but rather the establishment of a just and reasonable rate for new gas produced by pipelines. A rate that will allow the pipelines to hold on to their share of production, without unduly burdening the customers. A full area rate might allow the pipelines to increase their present share in production of new gas, but it is also likely to raise gas prices all around. Such a gas rate raise would not be in the public interest.

In brief, it is apparent that the recent area rate proceedings created a gas pricing environment which gives or promises to give the independent producers a certain competitive profit advantage over some of the pipeline gas producers. Moderate immediate corrective measures are in order. However, remedial action should be taken judiciously, and without unduly upsetting the presently existing competitive balance. It was demonstrated in this case that only under special circumstances is an increase in the production of gas by pipelines decidedly in the

[10130]

public interest. In most instances such increase would benefit the pipeline stockholders much more than the gas consumers. Too much incentive would likely result in increased charges to the consumers. The advantages of encouraging pipelines to produce gas do not lend themselves to quantitative measurement. Heretofore the cost-of-service method of regulation, which the Commission has been applying to the pipeline produced gas, maintained a healthy competitive atmosphere, under which individual pipelines prospered; where circumstances truly warranted it the pipelines produced adequate supplies of their own gas. El Paso, one of the largest gas producing pipelines, urged continuation of the *status quo.* It is noteworthy that El Paso has acquired leases in areas of major importance for current and future gas development, namely, in the Permian Basin and Anadarko Basin. There is reason to expect that in the future its production rates in such areas will be costed at a level not higher than from those of respective independent producers in that area. There is evidence in the record that because of higher cost and of accounting problems affecting a multitude of small producing enterprises, the Appalachian Area pipelines do not as yet readily lend themselves to the area rate pricing method.

The Pipeline Group as well as the Staff made a persuasive presentation that the Commission does have legal authority to prescribe the higher area rates for gas produced by pipelines, if and when it is proven that such increase will serve the public interest and be fair and just to every party affected by it. The pipelines argued that we can no longer remain in the regulatory era that existed before area rates, and must pursue the Supreme Court's decision in the *Permian Case,* which augments everything held thus far by the courts in prior contested utility rate cases. Area rates for jurisdictional gas produced by independent producers are here to stay. Pipelines producing gas for their own sales deserve competitive price consideration. The divergent equities must be balanced justly and fairly. Because of the

economic and financial complexities involved, changes should be embarked upon gradually, experimentally, and under proper regulatory surveillance. The regulatory cost-of-service method for new gas is no longer fair for pipelines facing competition from independent producers under area rates. The blanket area rate for pipeline producers advocated by the Pipeline Group is unfair to consumers and possibly also to the independent producers.

[10131]

If area rates are applied to all pipeline producers of new gas, such action may do harm to the Appalachian pipelines and to El Paso. Furthermore, such blanket rates could not be rolled back readily if and when these may be proven unjust and unfair to certain segments of the gas producing industry or to the users of gas.

The Staff and the Municipal Group submitted into the record convincing data showing that application of the straight area rates to new gas produced by the pipelines would result in windfalls to the pipeline stockholders coupled with correspondingly higher charges to the consumers. While the Examiner is in substantial agreement with the opponents of the straight area rates for pipeline gas, he finds that the modified area rate proposed by Staff will result in too many administrative, accounting and other regulatory problems. Most respondents had additional substantive complaints about this method. On the other hand, the orthodox cost-of-service rate regulation method advocated by El Paso and the Municipal Group fails to cope sufficiently with the new competitive problems created by the recently established area rates for new gas produced by the independent producers.

The Staff favors a method that would make it more advantageous for the Pipeline Group to produce more gas, but at the same time the Staff, quite properly, does not consider it fair for the Pipeline Group to get windfalls from an apparent favorable money raising position or from any produc-

[10131]

tion tax advantages. In other words, without specifically saying so, the Staff wants the pipeline producers to be in as good a position as the independent producers, but not in a better competitive position. The Staff, in fairness to all parties involved, and with special deference to the needs of the consuming public, is also trying to preserve the present competitive balance in the gas production industry. To achieve this, the Staff is willing to depart from the present cost-of-service method, which has been repeatedly sanctioned by the reviewing courts, and would try new approaches, which are in some respects radically different and thus far are objectionable to nearly everybody concerned. The modified area price advocated by the Staff is well intentioned but as so well demonstrated by the Municipal Group and by the Pipeline Group, will be most difficult

[10132]

to administer and there is serious doubt that it will bring about the commendable results envisioned by the Staff. The "Modified Area Rate" was vigorously objected to by all producers as well as all gas consumers, except perhaps by the Public Utilities Commission of California. We must then turn to a method that can be readily administered, that does not burn the bridges behind, that is likely to be less objectionable to most parties, and one that can be readily amended to meet the continuously changing competitive conditions. We need an experimental method that can remain under constant regulatory surveillance.

Accordingly, the Examiner makes the following general findings and conclusions: (a) Group I Pipelines (with production operations from owned gas reserves) should be allowed to share with the consumers certain tax deduction benefits from their production of new gas, and (b) The Group 3 On-System Pipeline Affiliates[1] and the Group 4 Off-System Pipeline Affiliates[2] should be allowed for on-system sales volumes the applicable area rates for 10 percent of their new gas production, but that the remainder of their

on-system sales volumes should be subject to the conventional cost-of-service regulatory method, without the benefit of sharing any federal income tax benefits from their production with the consuming public. New production sold off-system should receive the area or the in-line rate.

This will eliminate some inequities now existing between affiliates; some operate under settled rates, while other companies operate under strict adjudicated cost-of-service rates. The new benefits will be on a small scale in the early years following the order herein because they relate to future gas leases acquired (Phase 1), rather than to leases already acquired from which current gas is being produced. All affiliates should operate somewhat more fairly under the same easily administered 10 percent area rate formula.

---

[1] Anadarko Production Company, Colorado Oil and Gas Company, Lone Star Producing Company, The Preston Oil Company, Texas Gas Exploration Corporation and Union Producing Company

[2] City Service Oil Company, Columbian Fuel Corporation, El Paso Products, La Gloria Oil and Gas Company and Tenneco Oil Company

[10133]

The Examiner expects these rulings to be of benefit to the Pipelines and the consumers alike, because it will discourage further spin-offs of producing properties to affiliates. It will also permit the Group I Pipeline to obtain some tax deduction benefits similar to the ones obtained by independent producers operating under area rates.

The sharing of new gas tax deduction benefits by Group I pipelines, and providing area rates for 10% of new gas produced by Group III and Group IV Pipeline affiliates should prove an adequate but not an excessive incentive for these companies to continue their relatively modest participation in the gas production field. This will not upset the presently healty competitive balance. Should unforeseen, financial, economic or exploratory events occur, the Commission on its initiative or in response to applications could readily adjust the above prescribed quantities of incentive.

[10133]

A distinction needs to be made between (1) completely excluding tax benefits from production from cost-of-service computations and (2) sharing of tax deduction benefits from the production of new gas in the future. In the first instance such an allowance is tantamount to a production rate subsidy. The Municipal Group, as well as the Staff, have very properly pointed out that such a position has been clearly rejected by the courts and by this Commission. *E.g., Cities Service Gas Co.*, 30 FPC 158, 162, *set aside sub nom. Cities Service Gas Co.* v. *F.P.C.*, 337 F.2d 97 (CA10, 1964), but approved in *F.P.C.* v. *United Gas Pipeline Co.*, 386 U.S. 237 (1967). The second situation is quite different. The Pipelines have their choice of purchasing gas from independent producers at area rate prices or search for their own gas and produce it in instances where it can be obtained at the lower price. If they should share the production tax benefits with the gas consumer, this means slightly higher cost for gas to consumers to provide a minor increase in return to the pipelines. The sharing tax treatment equitably disposes of long standing, controversial tax credit benefits to consumers. It appears from the record that the significance of the tax credit benefit matter has been overstated in this proceeding.

The 50-50 sharing was arrived at as a matter of informed administrative discretion. It was felt that a lesser share to the pipeline producers would not be a sufficient inducement to search for new gas, while a higher share would not be fair to the consumers. This is intended as an interim experimental rate. It is designed to encourage pipelines to search for and

[10134]

produce new gas at the historical levels. These experimental rates will have to be kept under the Commission's surveillance. It is noted that even the area rates are still experimental. In the *Permian* case, the Supreme Court said "*** Moreover, area regulation of producer prices is avowedly

still experimental in its terms and uncertain in its ultimate consequences; it is entirely possible that the Commission may later find that its area rate structure for the Permian Basin requires significant modification." The same Opinion held "*** this Court has therefore repeatedly stated that the Commission's orders may not be overturned if they produce 'no arbitrary results.' *FPC* v. *Natural Gas Pipeline Co., supra,* at 586; *FPC* v. *Hope Natural Gas Co., supra,* at 602. Although neither law nor economics has yet devised generally accepted standards for the evaluation of rate-making orders, it must, nonetheless be obvious that reviewing courts will require criteria more discriminating than justice and arbitrariness if they are sensibly to appraise the Commission's orders."

Judging from the data contained in the former FPC cases, there is reason to conclude that sharing of tax deduction benefits as applicable to future gas will not amount to excessive monetary allocations. It will be only sufficient to make it worthwhile for the pipelines to search for new gas, but not enough to reach for a substantial increase in the level of production. In fact, this inducement is probably of the same order of magnitude of certain flexible expense allocations agreed upon by the parties in certain settled jurisdictional gas rate cases.

The proposal that pipeline affiliates be allowed the applicable area rate for 10% of future gas production is believed to cause only a slight departure from the present setup. It would recognize the *di minimis* field prices already allowed by the Commission in some cases for pipeline affiliates (Tennessee). It is a method which can be readily administered. It will not require excessive separate accounting. It will take part of the guesswork out of future gas exploration ventures, and it is anticipated that such advance determination will make it less conducive for pipelines to transfer producing property to affiliates.

The 10% level was arrived at as a matter of informed administrative judgment. It could readily be contended that . . .

[10134]

a higher or a lower percentage could equally be made applicable. It is an experimental step. The results should be properly evaluated at a later date.

[10135]

C. *Sharing of Tax Benefits from Future Production*

The advent of area rate pricing for independent producers has created a competitive condition whereby the adequacy of cost-of-service regulatory rate treatment accorded pipeline producers in the past is now seriously questioned. It is intended herein to correct in some measure for the disparity of new gas area rate treatment accorded independent producers and certain pipeline producers.

When gas prices were set in *Permain* for independent producers, the Commission for the first time embarked upon a new program which provided current costing for new gas. This costing method provided, in addition to more liberal production allowances than pipeline historical costs of production, a higher rate of return than pipeline producers are permitted and more liberal income tax treatment.[1] Pipeline producers regulated under the cost-of-service method, which means pricing at cost plus a fair rate of return on their investment in produced gas from future acquired leases, are likely to encounter problems when competing with independent producers benefiting from the more liberal treatment under area rates for new gas. Some remedial provision seems warranted.

[1] The independent producers in *Permian* were allowed zero Federal income taxes, which while this did not provide any unit (MCF) cost component in the allowed price of the gas itself, did in effect free the producers to use the tax deductions from production to reduce taxes payable on nonjurisdictional taxable income. Not so, however, in the case of pipeline producers that are regulated as to their rates on cost-of-service with Federal income taxes calculated on the actual taxes payable basis; here all tax deduction benefits from the production of gas are assigned first to offset or eliminate production taxable income, and then these deductions spillover to reduce taxable income of the other utility functions, such as transmission and distribution, which, of course, are jurisdictional.

It is intended as a policy matter to permit the pipeline producers (Group 1) a separate special tax benefit allowance as part of a future cost-of-service determination, which would

reflect the difference between a calculation of the overall actual Federal income taxes payable, and a similar determination of tax which would divide equally between the company and the rate-payers, the spillover benefits, when available from the production function that arise from only the two major tax deductions, statutory depletion and intangible drilling costs. Whereas, formerly, all spillover benefits inclusive of these two major tax deductions were assigned entirely to the ratepayers, they now would be assigned under a separate tax calculation for these two major tax deductions arising from future gas leases acquired, one-half to the ratepayers and this would leave the other half of these benefits to become the basis for a separate special tax allowance in the cost-of-service. Under the separate tax calculation, actual taxes payable under cost-of-service, embracing all tax deductions including statutory depletion and intangible drilling costs, as in past determinations, would prevail up to the point of determination of spillover arising from the two major tax deductions. It should be made clear that the original cost-of-service prepared, reflecting actual taxes payable, should not be otherwise adjusted than by the showing of the above mentioned special tax allowance.

This special tax allowance is intended as a benefit to the pipeline producers arising from certain statutory tax deductions, but not as having any effect on the computation or amount of the tax cost under the "actual taxes payable" concept. The "actual taxes payable" tax cost is not to be disturbed. The special allowance is intended to be an additional return on pipeline production investment. This is consistent with the court's mandate where in reversing the Commission's "tax savings" return formula in *El Paso* the Court of Appeals said:

[10136]

> . . . It is the duty of the Commission to fix a rate that represents the cost-of-service and a reasonable return on the investment, including compensation for consumption of the gas and an increment for incentive, instead of merely *treating* the tax savings as the amount necessary to provide for return and incentive. This can be done only by making the necessary inquiry directed to this issue, building up a proper record, and making findings on the amount *actually necessary* to provide these items. (281 F.2d 567 at 573 (1960))

[10137]

The special tax allowance here made is intended to fulfill the requirement called for in the above quote by the words, "including compensation for consumption of the gas and an increment for incentive". It should be explained that the formula used by the Commission in the above case to provide the "tax saving" return for the well-mouth properties of El Paso is fundamentally different, both in substance but more so in application than the 50-50 sharing benefit recommended herein. *The "tax saving" return provided no benefit for the ratepayers. It could only increase their rates–not lessen them, while the 50-50 sharing divides the tax benefits of a future venture equally between the pipeline company and the ratepayers.*

As to the application, in the above cited case the orthodox 6% return on well-mouth (production) properties was completely replaced by the "tax savings" return approved by the Commission, because it just happened, according to the calculation of the tax benefits *for that company at that time,* to provide a more liberal return allowance (8.61 per cent) than the amount of return figured on the orthodox 6% basis applied to the production investment. If statutory depletion and intangible well drilling costs had been a greater amount for the period, the "tax savings" return might have escalated to 10 or 12 per cent or even more, instead of the 8.61 per cent determined. However, when it came to the

United Fuel case (23 FPC 127 and 512) the attempt at substitution of a "tax saving" return did not materialize because the "tax saving" return formula did not yield as sufficient an amount of return as was available by applying the orthodox 6-1/4 per cent to the production investment.

Thus, we see that under the "tax savings" formula as formerly attempted, the Commission could not be at all certain that pipeline production property investment would receive a greater or lesser return that would be provided under the traditional percentage of return applied to that investment. Nor could it be sure as to the extent of the increase to the production rate of return. The "tax saving" formula apparently could not be applied fairly and impartially to all pipeline producers' well-mouth property.

[10138]

The proposal to allow additional return on production investment using the new calculation involving the Federal income tax allowance would provide a cost-of-service benefit for all pipeline producers in all cases where spillover from production becomes available from the two above mentioned tax deductions. The tax benefit under this proposal as related to an increase in the rate of return is decidedly more limited and exacting than in the *El Paso, supra,* case using the "tax savings" return. This is so because:

> (a) the proposal herein provides benefit only if spillover occurs in the production function arising primarily from the two tax deductions, and
>
> (b) it is shared between the company and the ratepayers.

Granted, both formulas have the same goal in mind—a more liberal allowance to the pipeline having production investment and some incentive to encourage still further production. However, it is anticipated that the 50-50 sharing method will more fairly provide and will more accurately gauge this allowance deemed essential in the present case.

[10138]

In summary, the separate special tax allowance can be determined readily (as far as the Federal income tax calculation is concerned) at 52% (the FIT rate for illustrative purposes) of one-half the combined total of the two deductions (or 26% of combined total of the two deductions). In addition, however, there are as part of the computation of the special allowance some minor effects from the application of the sharing of the tax deductions as regards to an increase in state income taxes, where these taxes are calculated as a percentage of the Federal income tax, but this is largely offset by a minor decrease in the amount of the return in this tax calculation. The attached Appendix D shows a Federal income tax calculation, illustrating the detailed application of the 50-50 sharing of the benefits from the two tax deductions. This illustration compares with the tax calculations that were prepared in the *Southern* (29 FPC 323 and *Panhandle* (25 FPC 787) rate cases, which were examined in order to test the extent of tax benefits proposed herein. It is understood that in current rate settlement cases the calculation of the Federal income tax

[10139]

allowance may not include a reduction of working capital (affecting return) from the income tax credit and also, that the now basic 48 per cent tax rate has been increased by the 10 per cent surtax (Act of June 28, 1968, P. L. 90-364), making the current rate in effect–52.8 per cent.

As explained before, the equal sharing of tax benefits is to be confined to the two major tax deductions, statutory percentage depletion and intangible drilling costs, and the adjustment reflecting the 50-50 sharing would have to be appropriately apportioned between jurisdictional and nonjurisdictional service. These benefits, to the extent they would be available, would relate only to future gas production and would become determinable from the tax returns of the pipeline for cost-of-service determinations, as they occurred after the date of the order in this proceeding.

There, of course, would be no special tax allowance from these tax deductions under conditions of a positive Federal income tax payable on future production where no spillover of benefits from the production function would arise.

There is no intention of extending the spillover benefits proposed here to any pipeline affiliates. This is explained in the next section about treatment of affiliates' gas sales. It is intended by this decision to foreclose entirely any further pipeline production incentive allowance in the rate of return allowance in any and all cost-of-service rate cases occurring after the date of the order in this proceeding.

D. *On-System and Off-System Sales by Affiliates*

It is intended herein to price future on-system sales of gas produced by pipeline affiliates from leases acquired after the date of the Commission order in this proceeding. Off-system sales of flowing gas by pipeline affiliates to non-affiliated parties are understood to be made at either in-line or full area rates. There appears to be no issue in this proceeding as to the future pricing of off-system sales by pipeline affiliates, which may be expected to continue at either in-line or full area rates.

The Staff did not consider certain problems when it comes to prescribing appropriate rate treatment for affiliates' future gas sales.

[10140]

As mentioned before, the Examiner deems it desirous that future on-system gas will continue under cost-of-service pricing, not only for pipeline producers (Group 1), but also to the largest practical extent for both on-system affiliates (Group 3) and off-system affiliates (Group 4). However, he is mindful that some of these affiliates in both Groups 3 and 4 are now making on-system sales, including *de minimis* on-system sales, at prices ranging from cost-of-service to full area rates.[1] Largely for this reason the Examiner, while proposing to deny any sharing of tax benefits to these pipe-

line affiliates (Groups 3 and 4), concludes for these pipeline groups that: (1) up to ten per cent of the Mcf volumes of all new gas produced and delivered on-system by a selling affiliate in any one year (but in no event should such volumes exceed one-fourth[2] of the affiliated purchasing pipeline's total annual supply necessary to meet gas requirements of jurisdictional customers) be excluded from cost-of-service [or other pricing], and be allowed either full area rates, where available, otherwise the applicable in-line rates. The emphasis here, however, is on the remaining large percentage of the future volumes of affiliates' on-system gas which should be regulated uniformly under the cost-of-service pricing method, rather than at various settlement rates which may become uneven as between various affiliate producers as well as unfair among consumers.

Ten per cent of total gas produced is purely an administrative judgment figure. It is an informed determination. It seems most nearly appropriate under the present circumstances of these affiliates regarding their prices and volumes sold on-system and off-system. It is purposely intended to relate the percentage to total overall production volumes, rather than a percentage of total gas delivered on-system, because the volumes sold on-system receiving the area price would be somewhat greater.

---

[1] *Union Producing Company*, 31 FPC 41, p. 53. Initial Brief of Cities Service Oil Company and Columbian Fuel Corporation, p. 17. Initial Brief of Tenneco Oil Company, p. 18.

[2] Humble Oil, although not presently making any on-system sales to its pipeline affiliate, Humble Gas Transmission, may do so in the future. Humble produces over 1 billion Mcf of gas annually, making it necessary to apply the one-fourth volume limitation, in order to keep affiliate sales in a *de minimis* category, and to limit further any prospective on-system sales volumes to its affiliate.

[10141]

It is also intended that wherever the percentage of volumes (up to 10 per cent) to be allowed the area rate in each area for on-system gas supersedes the pricing of those same volumes on the cost of service basis, that the latter pricing be on an averaged cost basis in each area for the period. This requirement, of course, is deemed necessary to prevent any attempt to an affiliate producer to apply area rates selectively to accomplish a further price advantage.

The ten per cent will apply to the total of future gas production volumes and is intended to fully exempt from cost-of-service pricing those affiliates having truly *de minimis* on-system volumes of sales, as shown by the volumes percentages sold on-system indicated by the data available in the record. Additionally, for the remainder of the affiliates it will afford a measure of price parity, since ten per cent at higher area prices is obviously preferable than the lower cost-of-service rate allowances.

Only Tenneco Oil Company, Cities Service Oil Company, Columbian Fuel (merged with Oil Company effective July 1, 1968) and La Gloria Oil and Gas Company would be completely exempt from cost-of-service pricing on the basis of their 1965 on-system sales volumes as related to their total production of gas. The remaining seven affiliate respondents appear to be all over twenty per cent in their on-system sales volumes, with a number of affiliates apparently exceeding seventy per cent, based on the 1955-62 group on-system percentages related to their total production. (Exhibit 4, Schedule 6)

Since the ten per cent is applicable to future pricing of total gas produced, the remaining seven affiliates will be able to evaluate and adjust their on-system and off-system sales volumes to best meet the ten per cent pricing differential requirement, should they care to do so.

For those affiliates whose on-system sales volumes are expected to exceed the ten per cent of total production

[10141]

price differential, record-keeping will be required to show the average cost of service of the total volumes of gas produced by each affiliate on a yearly basis. As previously mentioned, this will be necessary in order to substitute the area or in-line price for the ten per cent of total volumes produced

[10142]

which are sold on-system. This record-keeping procedure will provide the Commission with the opportunity to review each affiliate's actual cost of all gas produced, including the actual cost of those volumes receiving area or in-line prices. Periodic review of these costs and selling prices may lead the Commission to alter in a future case the ten per cent price arrangement.

The Commission's deviations in pricing affiliates' gas spread over at least the past ten years, largely supported only by the classification of *de minimis* sales on-system, caused the Examiner to conclude that a reasonable approach for affiliates' future gas sales would require: (a) a setting of a maximum percentage of affiliates' volume of total production as being an appropriate volume of on-system sales of gas considered *de minimis* and (b) a like treatment for all affiliates making on-system sales as to the pricing of the gas itself; regardless of the many statements that have been offered to justify particular price treatment.

Generally speaking, all affiliate respondents requested full area or in-line rates for all of their future on-system sales. The *de minimis* or otherwise on-system sales volume and dollar price picture for both Groups 3 and 4 affiliates is not at all clear and complete on this record. This was probably due to the nature and direction of the case, with primary emphasis by proponents including the Staff advocating and supporting area rates in some form, and opponents arguing against any change in method of pricing. It would have been enlightening to have had the data made available on the record showing for each affiliate what was demonstrated

only by groups in a Staff exhibit. (Exhibit 4, Schedule 6) These volumes and percentages sold on-system do not give the appearance of being *de minimis*. No group percentages are available beyond the year 1962; however, several companies have indicated their more recent on-system sales are in a much more *de minimis* posture as related to their total natural gas sales, both as to volumes[1] and as to revenues received.

[1] Cities Service Oil Company shows on-system sales volumes in 1965 of 6.3% of total gas sales volumes; in 1966–5%, Vol. 7, Tr. 440; Vol. 8, Tr. 791; Columbian Fuel Corporation

[10143]

Only Group 1 pipeline producers are intended to benefit from the sharing of spillover of tax benefits, to the exclusion of all pipeline affiliates. Since cost-of-service determinations of rates are required for most affiliates as related to future sales of on-system gas, the determination of Federal income taxes by them for cost-of-service purposes should be on an "actual taxes payable" basis for an affiliate filing an individual return; whereas on a consolidated reutrn basis the entire spillover of tax benefits from affiliates' production should be reflected as a reduction in the consolidated effective tax rate. The reasoning that underlies the preferential tax treatment for pipeline producers (Group 1), in addition to affording them some measure of parity with independent producer rates, is to provide some encouragement to the pipeline producers to retain their future acquired producing properties.[2] Whether or not an affiliate might choose to transfer its existing and future acquired gas producing properties to its affiliated transmission pipeline in order to have these properties share in the tax benefits here proposed, will rest upon each management's decision after reconsidering all factors which led to the alienation of its producing properties in the first instance. This does not say that sharing of the tax benefits, if the affiliate

properties were to be transfered to the parent, are sufficient incentive to accomplish this purpose,

[1] Continued from previous page
shows on-system sales volumes related to total gas sales volumes in 1965 of 22.7%; in 1966–20.3% Vol. 7, Tr. 440; Vol. 8, Tr. 787, 788. The merged on-system sales volumes of Cities Service Oil and Columbian Fuel for 1966 would be 8.3% of total gas sales volumes. Tenneco Oil shows on-system sales volumes related to total gas sales volumes in 1965 of 2.5% Vol. 7, Tr. 399. La Gloria Oil and Gas Company shows on-system sales in 1965 of about 8% Vol. 7, Tr. 444.

[2] *** If the Commission contemplates increasing rates for the purpose of encouraging exploration and development, or the ownership by pipeline companies of their own producing facilities, it must see to it that the increase is in fact needed and is no more than is needed, for the purpose. *** *City of Detroit* v. *F.P.C.*, 230 F.2d 810 (CADC, 1956)

[10144]

but it is based on reasoning that providing these benefits only to the pipeline producers will help deter further alienation of existing and future acquired producing properties and this is in the consumers' interest.

In summary, the intention here in this decision is to recognized that an opportunity should be made available in Phase I, to correct some of the inequalities in the allowed current pricing of gas among pipeline affiliates, to eliminate *de minimis* volumes of sales from the cost-of-service pricing method for affiliates in those instances where the label *de minimis* sales truly applies, and most importantly to encourage pipeline producers to retain future acquired producing properties.

The Examiner finds that other than specifically provided herein, there is no basis in the record for accepting the producer-intervenors' suggestion that the rates prescribed herein contain conditions or restrictions affecting the pipeline production and sales of gas, such as delivery, pipeline quality and rate of take.

[10145]

X. SUNDRY RULINGS

A. *Request to Change Effective Date*

The Pipeline Group asked that the cut-off date between Phase I and Phase II of this proceeding be established at 1/1/61 or–at the very latest–6/29/64, the date of the Commission's order announcing its intention to determine whether pipeline production should be regulated on an area basis. The Group further urged that the availability of Phase I treatment should turn on either the date of discovery or the date of first delivery of natural gas, but not on the date of lease acquisition.

The Staff recommended that the determination in this Phase I of the instant proceeding be applicable only to gas produced from leases acquired after the date of the Commission Order herein. Tennessee agreed with this recommendation, and hence, opposed the suggestion advanced by the Pipeline Group that the cut-off date be moved back in time or that the critical event triggering the application of the cut-off be something other than the acquisition date of the leases, or both. The effect of adopting either one or both of these proposals is to make retroactive the Commission's determination herein. Tennessee believes that any such retroactivity would be unwarranted and inequitable.

The Examiner notes that the Commission's Order dated April 13, 1966, provided in so many words that any Commission determination in this Phase I of the instant proceeding should be applicable to gas produced "from leases acquired after the date of determination." 35 F.P.C. 497, 499. Accordingly, there is no reason to fix a cut-off date earlier than the date provided therefor in the Commission's Order. Since the Examiner's findings in this Phase I, are based on the need for an incentive to produce new gas in the future, it is concluded herein that the rates proposed are to take effect as of the date of new lease acquisition,

which will occur after the date of issuance of the Commission's final opinion in these proceedings. Accordingly, the Pipeline Group's request to change the effective date of Phase I of this proceeding is herewith denied.

[10146]

B. *Motion for Severance*

In a motion filed July 5, 1968, Union has moved "that it be grouped with other independent producers so that it will receive the same method of regulation and rates which are accorded other independent producers, and that it be discharged as a party to this proceeding." In this motion and in its accompanying brief Union largely argued the merits of the rate treatment which should be accorded its "sales" to its affiliated pipeline, United Gas Pipeline Company.

Union argued that it functions like an independent producer and that application of a different rate treatment to Union would not provide it with sufficient funds to continue its operations. The Commission has previously decided that Union is the "producing arm" of United Gas Pipeline Company. *Union Producing Company*, 34 FPC 41, 42-44 (1964). Union's claim that it functions like an independent producer, merely argues the ultimate determination in this case of how either Union's sales to United should be treated or how inter-affiliated sales as a class should be treated. The Examiner finds and concludes that Union's claim is addressed to the merits of the proper pricing of affiliated production and provides no reason why Union should be dismissed from this proceeding. Accordingly Union's motion to be discharged from these proceedings is herewith denied.

XI. ADDITIONAL FINDINGS AND CONCLUSIONS

Upon consideration of the entire record in this proceeding, the evidence adduced and the briefs filed, the Presiding Examiner finds and concludes, in addition to the findings

[10146]

and conclusions hereinbefore stated, that

(1) Each of the respondents[1] listed in Appendix C was, a

[1]Where the term "respondents" is used in the finding and ordering paragraphs hereinafter set forth, it is to be regarded as referring to all named respondents in the Commission orders issued in this case, and to all parties on whose behalf such named respondents will file FPC gas rate schedules for sales in the Continental United States on and after the date of the issuance of the Commission's final order in this proceeding.

[10147]

natural gas company within the meaning of the Natural Gas Act and is or in the future may be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of this Commission.

(2) Proposed sales of natural gas to which the order herein applies are subject to the jurisdiction of this Commission.

(3) Rates for all sales of new natural gas, produced by the respondents herein, that will be above the applicable rates prescribed herein, will be held as not just nor reasonable or otherwise lawful under the provisions of the Natural Gas Act and sahll be disallowed, and refunds shall be required when warranted.

(4) The just and reasonable rates for proposed sales of new natural gas to which this order applies namely, after the issuance of a final Commission order herein, are the applicable rates set forth in ordering paragraphs (a) and (B) below.

(5) Contracts providing for rates in excess of the applicable just and reasonable rates determined herein are in that respect unjust and unreasonable, and shall be appropriately amended.

XII. ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or upon its own motion as provided in the Commission's Rules of Practice and Procedure, that:

A. In cost-of-service rate making cases determining prices for sales of jurisdictional gas by Group 1 pipelines, the tax computation shall be liberalized to include the equivalent of one half of the available tax benefits attributable to the tax deductions for percentage depletion and for intangible well drilling costs, as these deductions relate to new gas produced by these pipelines. See Appendix D.

[10148]

B. In rate cases fixing prices for gas produced from leases acquired by Group 3 and 4 pipeline affiliates:

(1) Up to 10 percent of the total Mcf volumes produced in any one year by a pipeline affiliate shall be sold and delivered on-system at a price not higher than the same or equivalent price as the in-line or area rate appropriate in the several areas as determined (or to be determined) by the Commission. However, in no case should such in-line or area rate volumes exceed one-fourth of the affiliated purchasing pipeline's total annual supply necessary to meet gas requirements of jurisdictional customers.

(2) For the remaining Mcf volumes of gas produced and available for sale in the same period by the pipeline affiliate: (a) the volumes sold and delivered on-system shall be priced on the traditional cost-of-service basis (without any sharing of tax benefits, as prescribed herein for Group 1 producing pipelines); and (b) those Mcf volumes sold and delivered off-system may be priced at the in-line or area rate appropriate in the several areas as determined (or to be determined) by the Commission.

/s/ Allen C. Lande
Presiding Examiner

[10149]

APPENDIX A
RP66-24
Page 1 of 2

Parties Filing Briefs

	Initial	Reply
Joint Brief of Pipeline Production Group	x	x
Cities Service Gas Co.		
Colorado Interstate Gas Co.		
Kansas-Nebraska Natural Gas Co.		
Lone Star Gas Co.		
Natural Gas Pipeline Co.		
Northern Natural Gas Co.		
Panhandle Eastern Pipeline Co.		
Southern Natural Gas Co.		
Taxas Gas Transmission Corp.		
Transcontinental Gas Pipeline Corp.		
Trunkline Gas Co.		
United Fuel Gas Co.		
United Gas Pipeline Co.		
El Paso Natural Gas Co.	x	x
Joint Brief for Consolidated Gas Group	x	x
Consolidated Gas Supply Corp.		
Iroquois Gas Corp.		
United Natural Gas Co., subsidiaries of Natural Fuel Gas Co.		
Kentucky West Virginia Gas Co.		
Philadelphia Gas Works, a Division of UGI Corp.		
Public Service Electric and Gas Co.		
Tennessee Gas Pipeline Co.	x	x
Tenneco Oil Co.	x	x
Humble Oil & Refining Co. and Humble Gas Transmission Co.	x	
Continental Oil Co.	x	x

Texaco Inc.		
Pan American Petroleum Corp.		
Mobil Oil Corp.		
Amerada Petroleum Corp.		
Shell Oil Co.	x	
Gulf Oil Corp.		
Warren Petroleum Corp.		

[10150]

APPENDIX A
RP66-24
Page 2 of 2

	Initial	Reply
Union Producing Co.	x	x
Cities Service Oil Co. and Columbian Fuel Corp.	x	x
People of State of California and Public Utilities Commission of the State of California	x	x
Municipal Gas Group	x	x
American Public Gas Association		
City of Chicago		
City and County of Denver		
Memphis Light, Gas and Water Division		
Public Service Co. of Colorado	x	
Staff – Federal Power Commission	x	x

[10151]

APPENDIX B
RP66-24
Page 1 of 6

List of Issues

THE ROLE OF PIPELINES AS PRODUCERS OF GAS

Does on-system pipeline production benefit jurisdictional customers of a pipeline's interstate system? In what respects? To what extent? Does pipeline production enable the pipeline producer to purchase gas from unaffiliated independent producers at lower prices than would otherwise be negotiated? What are the comparative systemwide average unit purchase gas costs of pipelines having internal production and pipelines relying entirely on outside production? What are the take or pay contract obligations, accrued prepayments, and makeup periods of each of the respondent pipelines?

Are there individual differences in pipelines necessitating one to have its own production while another need not? What are the consequences resulting from a pipeline's ownership of production of another's non-ownership of production? To what extent have pipelines used their own gas production to swing out for peaking and other purposes? To what extent has such swing been operationally or economically beneficial or necessary? To what extent have the swings of pipelines on their own production exceeded the swing normally available from independent producers?

Does off-system pipeline production benefit the jurisdictional customers of a pipeline transmission system? In what respects? To what extent?

Should pipelines be encouraged to engage in greater exploration and development activities or, in the alternative, to purchase acreate of proven reserves? Would expanded exploration and development activities of pipelines result in increased supplies of on-system gas? Would it be more eco-

nomical to acquire such gas reserves by purchase from independent producers?

Should pipelines be encouraged to acquire acreage in areas of proven reserves and produce their own gas? To what extent, during each of the last 10 years, have pipelines transferred acreage from unproven to proven gas accounts as opposed to purchases of proven gas acreage?

[10152]

APPENDIX B
RP66-24
Page 2 of 6

What amounts were spent during each of the last 10 years on exploration and development activities with respect to associated and non-associated gas wells?

Assuming that pipeline exploration and development of production should be encouraged, would that policy objective be best furthered by pricing pipeline production on an area rate basis or by continuing regulation on traditional cost of service principle? What impact does a policy of pricing off-system sales from pipeline production on an area basis have on the pipeline's incentive to make on-system sales? (A) under area rate treatment of all sales? And (B) under cost of service treatment of on-system sales?

Would area rate treatment effectively stimulate pipelines to engage in expanded exploration and development activity or in the alternative, would it merely cause them to step up purchases of and production from areas of proven reserve? Would expanded pipeline production adversely affect the exploration and development activities of large and small independent producers? In what respects? To what extent?

Assuming such an adverse effect, to what extent, if any, would this be offset by the expanded production activities and gas-finding activities of the pipeline company? If pipeline (and affiliate) production is to be neither encouraged nor discouraged, what is the most appropriate pricing method to be used for such production?

[10152]

Would permitting pipelines to participate as joint venturers with independent producers tend to impair arm's length bargaining betwen pipelines and independent producers to the detriment of the jurisdictional customers of the transmission system? Should rates for natural gas produced by a pipeline company and transported by it in its interstate gas transmission system be regulated under the same pricing method as that applied to sales of natural gas by independent producers? Should rates for natural gas sold to a pipeline company by a corporately related independent producer and transported by such pipeline

[10153]

APPENDIX B
RP66-24
Page 3 of 6

company in its interstate gas transmission system be regulated under the same pricing method as that applied to sales of natural gas by independent producers to unrelated pipeline companies? Should rates for natural gas sold to a pipeline company by some, but not all, corporately related independent producers and transported by such pipeline company in its interstate gas transmission system be regulated under the same pricing method as that applied to sales of natural gas by independent producers to unrelated pipeline companies?

If area rate treatment if otherwise appropriate, should pipeline produced gas be priced at the area rate which constitutes a ceiling price?

Would the recognition of contract prices set by a pipeline for its own departmental or affiliated production give appropriate recognition to the many factors normally entering into arm's length bargaining, and the determination of a fair and reasonable price between independent producers and pipelines?

Would it be appropriate and administratively feasible to allow pipelines instead of the area price, a weighted average

field price reflecting the current cost of buying comparable quality gas from independent producers?

[10154]

APPENDIX B
RP66-24
Page 4 of 6

THE DIFFERENCES BETWEEN PIPELINE PRODUCTION AND PRODUCTION OF OTHERS

What is the quantity of gas acreage and gas reserves presently owned by pipelines in the United States? Where is it located by county and state? To what extent is this acreage, (a) on-system or off-system, (b) associated or non-associated gas, (c) producing or shut-in?

What is the quantity of oil acreage and unproven acreage presently owned by pipelines in the United States? Where is it located by county and state? To what extent is this acreage (a) on-system or off-system, (b) associated or non-associated gas, (c) producing or shut-in?

What are the respective production figures from such oil and gas acreage during each of the past 10 years, segregated by county and state, and also between oil, casinghead gas, condensate liquids, and gas-wel-gas volumes?

To what extent, and in what respects, do pipelines operate their production properties in a different manner than do independent producers with respect to: (a) reserve to production ratio; (b) exploration and development as a percentage of total gross investment in producing lands; (c) total royalties per Mcf, segregated between land owner and overriding royalties; and (d) revenues earned from the sale of gas and from the sale of liquids.

What are the reasons for these differences between pipelines and independent producers when they are respectively engaged in production, and should the regulation of pipelines and independent producers reflect these differences or

[10154]

should it be on a uniform basis (a) under area rate treatment and (b) under cost of service.

To what extent is the risk assumed by pipeline producers different from the risk assumed by independent producers? How would expanded pipeline production be financed and under what conditions? What are the differences, if any, between such financing procedures and conditions and those under which independent producers must operate?

[10155]

APPENDIX B
RP66-24
Page 5 of 6

QUESTIONS OF REGULATORY POLICY AND LAW

If area rate treatment for pipeline production is otherwise appropriate, should pipelines be given the same area rate as an independent producer or should the applicable area rate be differentially adjusted—upwards or downwards—to reflect significant variations in (a) rate of return; (b) pay out or production period; (c) lease acquisition costs and overriding royalty payments; (d) Federal income taxes; (e) extraction revenues; (f) any other pertinent, operating or financial conditions? What should be the effect of pipeline (and affiliate) production area rates on various aspects of individual pipeline rate determinations, such as but not limited to rate of return and income tax allowance? For example, should Federal income tax deductions and liquid extraction revenues related to pipeline (and affiliate) production be reflected in the pipeline's jurisdictional cost of service?

Is either a temporary or permanent dual regulatory scheme for pricing pipeline production feasible? If so, what are the mechanics for applying area rates to future reserves while continuing the cost of service method with respect to dedicated reserves?

How could the Commission implement any policy decision to put on system pipeline production from future reserves

on an area cost basis in fixing the future rates of interstate pipelines? Would it have to rely upon Section 4 filings or Section 5(a) proceedings or is there some other available and administratively feasible and legal procedure?

Can pipeline production be priced at area rates before area rates are established in all producer pricing areas?

In the event of a policy determination to put pipeline production from future reserves on an area basis, can the guideline or in-line prices or some average of the two be utilized until just and reasonable prices are established for a particular independent producer pricing area?

[10156]

If not, is it either reasonable or feasible to have some of the on-system production from future leases priced on an area basis and some on a cost of service basis?

If something other than just and reasonable prices are used on an interim basis, should such use be made subject to refund? Where pipeline off-system production is made available to the pipelines' own systems through exchange agreements, how should the Commission price such exchange gas for each company when the exchanges are made in different areas having different area prices?

Is area pricing lawful for future reserves? As a matter of law, must area rates be applied uniformly to all pipeline producers or is it permissible to price the on-system production of each individual company on a cost of service or area rate basis, whichever is higher or lower?

To what extent, if any, should exceptions be made to the applicable area rates of pipeline production if priced on an area rate basis?

[10157]

APPENDIX C
RP66-24
Page 1 of 1

Parties-Respondents*

Alabama-Tennessee Natural Gas Company
Algonquin Gas Transmission Company
Atalntic Seaboard Corporation
Cities Service Gas Company
Colorado Interstate Gas Company
Consolidated Gas Supply Corporation
Cumberland and Allegheny Gas Company
El Paso Natural Gas Company
Florida Gas Transmission Corporation
Humble Gas Transmission Company
Kansas-Nebraska Natural Gas Company, Inc.
Kentucky Gas Transmission Corporation
Kentucky-West Virginia Gas Company
Lone Star Gas Company
Lone Star Gathering Company
Manufacturers Light and Heat Company, The
Michigan Wisconsin Pipe Line Company
Midwestern Gas Transmission Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
Northern Natural Gas Company
Ohio Fuel Gas Company, The
Oklahoma Natural Gas Gathering Corporation
Pacific Gas Transmission Company
Panhandle Eastern Pipe Line Company
Southern Natural Gas Company
South Texas Natural Gas Gathering Company
Tennessee Gas Transmission Company
Tennessee Natural Gas Lines, Inc.
Texas Eastern Transmission Corporation
Texas Gas Pipe Line Corporation
Texas Gas Transmission Corporation

Transcontinental Gas Pipe Line Corporation
Transwestern pipeline Company
Trunkline Gas Company
United Fuel Gas Company
United Gas Pipe Line Company

*Decision is not applicable to pipelines who are no longer producing gas for sale in interstate commerce.

[10158]

APPENDIX D
RP66-24
Page 1 of 11

TAX COMPUTATION ILLUSTRATIONS

The special tax increase allowance to be shown in cost-of-service resulting from the adjustment providing for a sharing of the spillover arising from the tax benefits is expected to vary in amount from pipeline to pipeline depending on its size and especially on the extent of its future exploration and production operations.

As is shown hereafter, the calculation of actual taxes payable should first be made with state income taxes and credit to working capital (affecting return) determined accordingly; then another calculation of federal income taxes on the 50-50 sharing basis would be made, along with state income taxes and adjusted return, the differences in federal and state income taxes and adjusted return should then be netted into one amount and placed in the cost-of-service (original "actual taxes payable" cost-of-service) as a separate special tax increase allowance. This procedure in treatment of the tax sharing benefit will enable all interested parties to readily see at all times the clear-cut effect of the benefit, rather than allowing it to be submerged in a revised tax calculation only.

Two major past rate cases where spillover was evident on the tax schedule were examined to test the level of magni-

tude of the proposed special tax increase allowance. The allowances relating to future gas would be on a much smaller scale resulting from future gas leases acquired. Still further testing of the approximate magnitude also may be found in this Appendix, p. 10.

In *Southern Natural Gas Company*, 29 FPC 323 at 358, the special tax increase allowance determined as a result of our application of the sharing of the tax benefits was

[10159]

$378,756.[1] which figured as a .304 percent (nearly 1/3 of 1%) increase in cost-of-service. When related to the amount of return ($14,728,025) determined at 6.24 percent, the increase was 2.56 percent. When the 2.56 percent was applied as an increase to the overall rate of return of 6.24 percent, the increase in tax brought it to 6.40 percent.

The second case tested was *Panhandle Eastern Pipe Line Company*, 25 FPC 787 at 860. Following the pattern of application of the spillover of tax benefits used in the *Southern Natural* case, the increase determined in the federal income tax allowance (interstate) was $598,195 (omitting state income tax increase and adjusted return decrease), which amounted to

[1]Details of the application are: At line 21, there is shown a distribution of well-mouth taxable income deficiency of $1,440,142 which is applied to taxable income, line 20. We replaced line 21 with our "adjustment of $725,917 to reflect 50-50 sharing of spillover arising from statutory deplection and intangible drilling costs", which when applied to taxable income, line 20, increased taxable income for total system gas operations from $14,406,094 to $15,132,011, and at the same time reduced the well-mouth taxable income deficiency (line 20) from $1,440,142 to a deficiency of $714,225. This remaining taxable income deficiency of $714,225, under Natural gas production, well-mouth was then distributed to the other utility functions, consisting mainly of the transmission and distribution functions. Our adjustment of $725,917 was composed of statutory depletion of $1,123,602 and intangible drilling costs of $328,231, totalling $1,451,833 (Staff Ex 26, Sch 5) which divided in half

amounts to $725,917. Our adjustment increased taxable income to $15,132,011, causing the federal income tax to increase from $7,485,-669 to $7,863,146, or an increase in tax of $377,477 (52% of $725,-917). As a result of the sharing of the two tax deductions, there was also an increase of $12,703 in state income taxes, which was nearly offset by a decrease in return of $11,424, so that the overall total of items comprising the special tax increase allowance amounted to $378,756.

[10160]

a .831 percent (or approximately 4/5 of 1%) increase in cost-of-service (interstate), and an increase of 6.60 percent when related to the amount of overall return ($9,065,096) originally determined at 5 3/4 percent. When related to the *overall rate* of return of 5 3/4 percent, the percentage increase of 6.60 percent increased the *overall* rate by .38 percent to 6.13 percent. This .38 percent is more than twice the increase in rate of return as shown in *Southern supra* (.16 percent), but it is still modest.

As indicated in the footnote[1] below, the Commission provided a "tax saving" return on the well-mouth properties in *El Paso Natural Gas Company*, 22 FPC 260, of 8.61 percent, which was 2.61 percent in excess of the 6 percent allowed on nonwell-mouth properties. The "tax savings" return in that case when included as part of the overall rate of return increased it from 6 percent to 6.35 percent, or an increase of .35 percent. So the increase (.38 percent) in overall rate of return of Panhandle resulting from the 50-50 sharing of the tax benefits is about the same as the "tax saving return" percentage increase allowed in El Paso (.35 percent), but the similarity ceases at this juncture, as indicated by our discussion of these two determinations in the decision. In *United Fuel Gas Company*, (23 F.P.C. 127, and 23 F.P.C. 512) no additional return beyond 6¼ percent was allowed on well-mouth properties because the calculation (the Commission followed same basis as used in El Paso) of the "tax saving" arising from percentage depletion and intangible

[10160]

drilling costs did not exceed 6¼ percent, so no additional return on well-mouth properties was provided.

---

[1] In Opinion No. 326, the Commission, while reaffirming its allowance of actual taxes in a rate determination and abandoning its previously indicated sanction of a phantom tax allowance, at the same time permitted producers to benefit from these tax provisions by computing the amount of tax savings at 52% arising from percentage depletion and intangible drilling costs, calling it "additional return from depletion and intangibles" and included it as part of the cost-of-service in lieu of a 6% return allowance on the well-mouth properties. The "tax savings" return on well-mouth properties resulted in a rate of return of 8.61 percent while 6 percent was allowed on non-well-mouth properties.

[10161]

A further effort was made to arrive at some overall approximation of the yearly increase in tax allowance that would have been provided the Group 1 pipeline producers (18 companies) from the 50-50 sharing of the tax benefits here proposed. Appendix D, page 10 shows that by revising the tax deduction totals furnished by Staff Witness Raymond on Exhibit 1, Schedule 4, to conform with our proposal, we determine an increase tax allowance of between 10.8 and 13.5 million dollars per year for all 18 companies if it had been applied to the period 1960-1962. This would average from $600,000 to $750,000 of tax benefits per company per year. This was arrived at in the following manner.

Staff Witness Raymond sponsored Exhibit 1, Schedule 4, titled "Tax Deductions from Gas Production for the Years 1960-1962–Based on Schedule 7 of the Pipeline Production Questionnaire." The schedule shows summarized yearly totals, reported by 18 producer pipeline respondents, of intangible drilling costs and statutory depletion deducted on their federal income tax return and the depletion (cost) deducted on their books. For 1960 the total excess of the intangible drilling costs and statutory depletion over cost depletion from gas production for the 18 companies was $33,912,911; for 1961, $38,937,092 and for 1962, $42,-

465,604. The average amount per company for each of these years would be:

1960	-	$1,884,000
1961	-	$2,163,000
1962	-	$2,359,000

However, by far the largest amounts for one company in that average, El Paso, had amounts for 1960–$9,006,500; 1961–$11,146,417; 1962–$12,556,418.

The proposal in this decision deals only with the benefits from the two tax deductions, intangible drilling costs and statutory depletion. Excluded are the offsetting amount of cost depletion from this calculation, so, of course, we would have had larger totals by the amount of the cost depletion if we had prepared Exhibit 1, Schedule No. 4, instead of Witness Raymond submitting it.

[10162]

The record does not provide the amounts of cost depletion for the 18 companies, so it was decided for our purposes to examine the *Southern* (29 FPC 323) (1963) and *Panhandle* (25 FOC 787) (1961) rate cases (which were previously reviewed herein) and determine a rough percentage of the relationship of the total of intangible drilling costs and statutory depletion offset by cost depletion for these two cases (which is how the figures are submitted net by Witness Raymond on Schedule No. 4 for the 18 producing pipelines) to the total of the intangible drilling costs and statutory depletion amounts only for these two companies. We found that by excluding cost depletion there was a 22.5 percent increase as shown in Appendix D, page 11. Appendix D, page 10 shows the application of the 22.5 percent to the tax deductions (net) from Exhibit 1, Schedule 4, to arrive at an approximation of the totals of intangible drilling costs and statutory depletion *only* for the 18 companies for the years 1960, 1961 and 1962. Page 1 also shows the total tax increase that would result from applying

the 52 percent tax rate to the tax deductions. Finally, the showing of the increase in tax allowance in cost-of-service for these companies that would result from a 50-50 sharing of the tax benefits as we propose herein.

A B C Gas Pipeline Company
Summarization of Effect of 50-50 Sharing of Tax Deductions and Determination of Special Tax Allowance in Cost-of-Service
12 Months Ended December 31, 1959

	Total Interstate System
Federal income tax reflecting 50-50 sharing of spillover of statutory depletion and intangible drilling costs	$ 16,697,192
Federal income tax on actual taxes payable basis	15,675,255
Difference - Total increase in Federal income tax ($1,965,264(A) x 52% equals $1,021,937)	1,021,937
State income tax reflecting 50-50 sharing - based on Federal tax	642,408
State income tax based on Federal tax using actual taxes payable basis	603,102
Difference - Total increase in State income tax	39,306
Returns at 6% adjusted, reflecting 50-50 sharing of spillover of tax deductions	30,090,112
Returns at 6% adjusted, reflecting calculation of Federal income taxes on actual taxes payable basis	30,119,850
Difference - Total decrease in return	(29,738)
Combined total of differences above - net (Special Tax Allowance)	$ 1,031,505(B)
Effect of special tax allowance on cost-of-service - not determinable in this sample calculation	
Effect of special tax allowance on amount of return at 6% under actual taxes payable basis - $1,031,505 divided by $30,119,850 equals	3.42%
Effect of special tax allowance on rate of return at 6%	

Rate of return at	6%
Apply sharing increase percentage	3.42%
Percentage increase in rate of return	.2052%
Rate of return	6.000%
Increased rate of return resulting from tax sharing	6.2052%

(A) See page 7 of Appendix D

(B) The special tax allowance would be shown in cost-of-service (determined as reflecting actual taxes payable basis) as a separate amount from the actual Federal income taxes payable of $15,675,255. There is no intention of changing cost-of-service which reflects actual taxes payable other than showing in it the special tax allowance. For example, there is no intention of changing the rate of return from 6% to 6.2052% and applying it to the rate base. All calculations of increases in taxes above shown are intended to be roughly comparable with determinations of increases in taxes for the Southern and Panhandle cases relating to past periods as reviewed herein. The special tax allowance relating to future gas, as proposed in Phase I, would result solely from statutory depletion and intangible drilling costs (per tax return) relating to production from leases acquired after the date of the order in this proceeding. These benefits would be small in the early years, but would become larger as more and more leases were acquired.

[10163]

[10163]

Docket No. RP66-24
Appendix D, p. 7 of 11

A B C Gas Pipeline Co.
Income Tax Computation Showing a 50-50 Sharing of Spillover of Statutory Depletion and Intangible Drilling Costs
12 Months Ended December 31, 1959

	Total Operations	Intrastate	Interstate: Total Interstate	Interstate: Natural Gas Production Well-Mouth	Interstate: Balance of Utility System, Transmission, Distribution, etc.
Net investment in plant	500,000,000	10,000,000	490,000,000	40,000,000	450,000,000
Working capital - preliminary	20,000,000	400,000	19,600,000	1,600,000	18,000,000
Rate base - preliminary	520,000,000	10,400,000	509,600,000	41,600,000	468,000,000
Return @ 6% - preliminary	31,200,000	624,000	30,576,000	2,496,000	28,080,000
Working capital - preliminary	20,000,000	400,000	19,600,000	1,600,000	18,000,000
Less: 48.5% of Federal income tax	8,241,271	143,133	8,098,138	-	8,098,138
Working capital adjusted	11,758,729	256,867	11,501,862	1,600,000	9,901,862
Rate base adjusted	511,758,729	10,256,867	501,501,862	41,600,000	459,901,862
Return @ 6% adjusted	30,705,524	615,412	30,090,112	2,496,000	27,594,112
Federal Income Tax					
Return on preliminary rate base	31,200,000	624,000	30,576,000	2,496,000	28,080,000
Less: 50.4868% 1/ of tax deductions of $16,000,000	8,077,888	181,752	7,896,136	2,090,154	5,805,982
Balance	23,122,112	442,248	22,679,864	405,846	22,274,018
Less: Surtax exemption 2/	5,340	102	5,238	94	5,144
Balance	23,116,772	442,146	22,674,626	405,752	22,268,874
Return and tax - above line divided by 49.5132% 1/	46,688,099	892,986	45,795,113	819,482	44,975,631
Less: Tax deductions	16,000,000	360,000	15,640,000	4,140,000	11,500,000
Taxable income	30,688,099	532,986	30,155,113	(3,320,518)	33,475,631
Adjustment to reflect 50-50 sharing of spillover arising from statutory depletion and intangible drilling costs	2,000,000 3/	34,736	1,965,264	1,965,264	-
Balance	32,688,099	567,722	32,120,377	(1,355,254)	33,475,631
Distribution of remaining well-mouth taxable income deficiency				1,355,254	(1,355,254)
Balance	32,688,099	567,722	32,120,377	-	32,120,377
Tax at 52%	16,997,811	295,215	16,702,596	-	16,702,596
Less: Surtax exemption	5,500	96	5,404	-	5,404
Federal income tax	16,992,311	295,119	16,697,192	-	16,697,192
State Income Tax					
Taxable income - Federal	32,688,099	567,722	32,120,377		32,120,377
Tax @ 2.0%	653,762	11,354	642,408	-	642,408

1/ See Sheet 8 of Appendix D
2/ See Sheet 8 of Appendix D
3/

Statutory depletion	2,500,000
Intangible drilling costs	1,500,000
Total	4,000,000
Divide above line by 2	2,000,000

[10164]

A B C Gas Pipeline Company
Income Tax Computation Actual Taxes Payable Basis
12 Months Ended December 31, 1959

	Total Operations	Intrastate	Interstate: Total Interstate	Interstate: Natural Gas Production Well-Mouth	Interstate: Balance of Utility System, Transmission, Distribution, etc.
Net investment in plant	500,000,000	10,000,000	490,000,000	40,000,000	450,000,000
Working capital - preliminary	20,000,000	400,000	19,600,000	1,600,000	18,000,000
Rate base - preliminary	520,000,000	10,400,000	509,600,000	41,600,000	468,000,000
Return at 6% - preliminary	31,200,000	624,000	30,576,000	2,496,000	28,080,000
Working capital - preliminary	20,000,000	400,000	19,600,000	1,600,000	18,000,000
Less: 48.5% of Federal income tax	7,736,871	134,373	7,602,498	-	7,602,498
Working capital - adjusted	12,263,129	265,627	11,997,502	1,600,000	10,397,502
Rate base - adjusted	512,263,129	10,265,627	501,997,502	41,600,000	460,397,502
Return at 6% - adjusted	30,735,788	615,938	30,119,850	2,496,000	27,623,850
Federal Income Tax					
Return on preliminary rate base	31,200,000	624,000	30,576,000	2,496,000	28,080,000
Less: 50.4868% 1/ of tax deductions of $16,000,000	8,077,888	181,752	7,896,136	2,090,154	5,805,982
Balance	23,122,112	442,248	22,679,864	405,846	22,274,018
Less: Surtax exemption 2/	5,340	102	5,238	94	5,144
Balance	23,116,772	442,146	22,674,626	405,752	22,268,874
Return and Tax - above line divided by 49.5132% 1/	46,688,099	892,986	45,795,113	819,482	44,975,631
Less: Tax deductions	16,000,000	360,000	15,640,000	4,140,000	11,500,000
Taxable income	30,688,099	532,986	30,155,113	(3,320,518)	33,475,631
Distribution of well-mouth taxable income deficiency				3,320,518	(3,320,518)
Balance	30,688,099	532,986	30,155,113	-	30,155,113
Tax at 52%	15,957,812	277,153	15,680,659		15,680,659
Less: Surtax exemption	5,500	96	5,404		5,404
Federal income tax	15,952,312	277,057	15,675,255	-	15,675,255
State Income Tax					
Taxable income - Federal	30,688,099	532,986	30,155,113	-	30,155,113
Tax @ 2.0%	613,762	10,660	603,102	-	603,102

48.5% - Percentage of tax available for working capital
52% - Federal income tax rate
6% - Rate of return

1/ 48.5% x 52% x 6% equals 1.5132%
52% less 1.5132% equals 50.4868%; 100% less 50.4868% equals 49.5132%
2/ $5500 x 48.5% x 6% equals $160.05
$5500 less $160 equals $5340

[10165]

Docket No. RP66-24
Appendix D, p. 9 of 11

A B C Gas Pipeline Company
Tax Deductions
12 Months Ended December 31, 1959

	Total Operations	Intrastate	Interstate: Total Interstate	Interstate: Natural Gas Production Well-Mouth	Interstate: Balance of Utility System, Transmission, Distribution, etc.
Interest on long term debt	10,250,000	180,000	10,070,000	950,000	9,120,000
Cost depletion per books	(1,500,000)	(120,000)	(1,380,000)	(1,380,000)	-
Book depreciation	(25,000,000)	(1,000,000)	(24,000,000)	(1,600,000)	(22,400,000)
Tax depreciation	28,000,000	1,100,000	26,900,000	2,200,000	24,700,000
Abandonment losses	100,000	20,000	80,000	70,000	10,000
Amortization of debt expense	200,000	30,000	170,000	50,000	120,000
Interest revenues	(50,000)	-	(50,000)		(50,000)
Statutory depletion	2,500,000	100,000	2,400,000	2,400,000	-
Intangible drilling costs	1,500,000	50,000	1,450,000	1,450,000	-
Total Deductions	16,000,000	360,000	15,640,000	4,140,000	11,500,000

[10166]

[10167]

APPENDIX D
RP66-24
Page 10 of 11

ESTIMATE OF TAX BENEFITS FOR GROUP 1

	1960	1961	1962
Tax Deductions (Net) Exhibit 1, Schedule No. 4	$33,912,911	$38,937,092	$42,465,604
Add 22.5% of above representing estimate of book depletion	7,630,405	8,760,846	9,554,761
Tax deductions from Exh. 1, Sch 4, excluding book depletion	41,543,316	47,697,938	52,020,365
Total increase in Federal income tax - 52% of above	21,602,524	24,802,928	27,050,590
Increase tax allowance to companies - 50% of above	$10,802,262	$12,401,464	$13,525,295

[10168]

APPENDIX D
RP66-24
Page 11 of 11

SUPPLEMENTAL TABLE

	Total System
Southern - (1963)	
Depletion, per books	$ (378,201)
Estimated Statutory Depletion	1,123,602
Intangible Drilling Costs	328,231
Total (Net)	1,073,632
Total (excluding book depletion)	$1,451,833
Panhandle - (1961)	
Depletion, per books	$ (319,849)
Statutory Depletion	1,840,195
Intangible drilling costs	501,087
Total (Net)	2,021,433
Total (excluding book depletion)	$2,341,282
Combined totals (Net)	$3,095,065
Combined totals (excluding book depletion)	$3,793,115

$3,793,115 ÷ $3,095,065 equals 122.5%, or an increase of 22.5% by excluding book depletion.

[10299]

BEFORE THE

FEDERAL POWER COMMISSION

Pipeline Production
Area Rate Proceeding

Docket No. RP66-24

STAFF BRIEF ON EXCEPTIONS

Robert A. Jablon
Commission Staff Counsel

Of Counsel:
Lloyd E. Dietrich

Washington, D.C. 20426
May 2, 1969

[10329]

line production has been and presumably will be no different from independently produced gas. (*E.g.*, 8(1)/688:1-21; 682: 19-683:10; Exh. 36). They also attempted to establish that variations among the unit costs of pipeline producers are similar to the random variations which might otherwise be expected. (*E.g.*, 8(1)/694:20-695:16, modified at 24/2669). However, as found by the Examiner (Decision, pp. 32-33, 37-38). The alleged randomness of pipeline company costs from definite patterns of high and low cost production among different companies. Decision,

---

[Footnote continued.]

Staff evidence in the aforementioned Area Rate Proceedings also show a difference in flowing gas exploration and development costs (using a modified Btu method), although one of lessor magnitude. Compare Ex. Nos. 55-J and 56-J, Sch. 1. Ex. No. 37,

[10329]

sponsored by the Pipeline Production Group and based upon the *Hugoton-Anadarko and Texas Gulf Coast Area Rate Proceedings*, indicates unit production and E&D costs for Tennessee Gas Transmission Company, El Paso Natural Gas Company and Texas Eastern Transmission Corporation of respectively 111.84 ¢, 46.18¢ and 26.33¢ per Mcf at an illustrative and unwarranted 12% rate of return. At an illustrative 6-1/2% rate of return, these costs would be 68.36¢, 30.90¢ and 22.59¢, respectively.

[10330]

p. 83. These vary with the respective dates of the companies' acquisitions of the predominant portion of their reserves. As is stated by Staff Witness Bass and quoted by the Examiner at p. 32 of his decision:

> * * * [M]ost of the pipeline producers are either in the lowest or the highest cost quartiles. * * * [T]hese groupings support the contention that there are two general groupings of pipeline producers: low cost pipelines that acquired low cost gas reserves relatively early in the history of the gas pipeline industry and pipelines that acquired their reserves more recently and at relatively higher costs. (38(1)/4098:3-22).

Furthermore, while of questionable validity for any purpose, the Pipeline Production Group cost exhibits 36 and 37 support the

[10452]

APPENDIX C
Page 1 of 1

APPENDIX C - CALCULATIONS ILLUSTRATING STAFF'S "MODIFIED" AREA RATES

Pipeline Production Area Rate
Docket No. RP66-24
Determination of Modified
Area Rates Based Upon the *Area Rate Proceeding (Permian Basin Area)*, 34 FPC 159, 192[1],
Using 6 1/2% Rate of Return

Excerpts from El Paso Natural Gas Company Brief on Exceptions

	Cost In Cents Per Mcf	
	Comm. Per. Pg. 40 Op. No. 468	Adjusted To A 6.5% Return
Exploration and Development Costs		
Dry Holes	1.42	1.42
Other Exploratory Costs	1.59	1.59
Adj. for Exploration in Excess of Prodn.	1.11	1.11
Total E&D Costs	4.12	4.12
Production Operating Expense	2.70	2.70
Net Liquid Credit	(3.10)	(3.10)
Regulatory Expense	0.14	0.14
DD&A of Production Investment		
Successful Well Costs	2.88	2.88
Lease Acquisition Costs	0.76	0.76
Cost of Other Prodn. Facilities	0.31	0.31
Total DD&A	3.95	3.95
Return on Production Investment	5.21	2.82
Return on Working Capital	0.35	0.18
Sub-total	13.37	10.81
Royalty at 12 1/2%	2.05	2.05
Production Taxes at 7%	1.01	0.82
Total Cost	16.43	13.68

[1]Calculations are from 20/2219 modified to show increasing allowed pipeline royalty rate component to 2.05¢. (Appendix A, pp. A-9 - A-10, *supra*.

* * *

[10561]

of rate ceilings" which "could be seriously disruptive of a pattern of uniform area ceilings." (34 FPC at 325). As to the latter, the holding of individual cost-of-service hearings would undoubtedly, as a pragmatic matter, mean that adequate regulation of independent producers would be impos-

sible under existing law. (*Phillips Petroleum Company*, 24 FPC 537 at 547).

b. The Production Operations Of Pipelines Are Not Comparable To The Production Operations Of Independent Producers

The record now before the Commission singularly demonstrates that the cost-price determined for independent producers in the *Permian* Opinion,[18] based on national data, is not representative and typical of the costs of pipeline producers. As the Examiner recognized at page 37 of his Initial Decision, this is mainly so because pipelines, unlike the major producers, have confined their drilling activities essentially to areas adjacent to their respective systems and have not operated on a national basis. In addition, the Examiner also found (page 37) that pipelines have emphasized: (1) drilling for gas rather than hydrocarbons in general (2) developmental drilling, and (3) shallower drilling. The differences in location and emphasis have caused the success ratios and drilling costs for pipelines to be noncomparable with those for independent producers.[19]

c. There Is Complete Lack Of Comparability Among The Production Operations Of Individual Pipelines

The record data tabulated below emphasizes the dispersions from average costs for the pipelines. Thus, regardless of whether Jones', Murr's, or Raymond's purported unit cost figures are used, *all* the cost data in this proceeding indicates that dispersion is the *rule* for pipelines' costs.

[18]34 FPC 159.

[19]See testimony of Witness Field at Tr. 4355.

[10562]

	Percent Deviation From Weighted Average Cost Per Jones Data All Groups[20] (1)	Pipelines (2)	Per Murr Data (3)	Per Raymond Data (4)
1. Tennessee Gas Transmission Co.	649.1%	405.4%	343.3%	174.8%
2. New York State Natural Gas Corp.	346.2	201.0	97.7	119.5
3. El Paso Natural Gas Co.	209.3	108.7	90.2	44.7
4. Hope Natural Gas Company	100.1	35.0	N.A.	72.2
5. Texas Eastern Transmission Corp.	76.4	19.0	59.4	66.8
6. Kentucky West Virginia Gas Co.	N.A.	N.A.	100.2	58.1
7. United Fuel Gas Co.	61.5	8.9	24.6	27.4
8. Mountain Fuel Supply Co.	36.8	(7.7)	(36.5)	12.2
9. Mississippi River Fuel Corp.	29.1	(12.9)	(32.7)	17.5
10. Southern Natural Gas Co.	23.7	(16.5)	(45.1)	8.5
11. Arkansas Louisiana Gas Co.	(10.7)	(39.8)	(34.4)	(18.6)
12. Panhandle Eastern Pipeline Co.	(39.9)	(59.5)	(55.0)	(51.4)
13. Kansas-Nebraska Natural Gas Co.	(41.7)	(60.7)	(72.3)	(76.6)
14. Humble Gas Transmission Co.	(48.5)	(65.3)	(65.5)	(45.7)
15. Colorado Interstate Gas Co.	(78.9)	(85.8)	(81.3)	(79.6)
16. Natural Gas Pipeline Co.	(82.4)	(88.1)	(84.8)	(81.7)

N.A.–Not Available

SOURCE: Column (1)–Schedule 21, page 1, Exhibit No. 58
(2)–Schedule 36, Exhibit No. 58
(3)–Schedule 35, Exhibit No. 58
(4)–Schedule 37, Exhibit No. 58

[20]Independents, Affiliates, and Pipelines.

[10563]

However, such wide variation *was not* the rule for the independents. As the Examiner found at page 38 of his Initial Decision, the record data based on Witness Jones' array data (which included independent producers, pipelines and affiliates) indicated that only 27% of the pipelines had costs which were within the quartiles surrounding the median for all groups, while 59% of the independents had cost so positioned in the array.[21] More meaningfully, it was also shown that the average percentage deviation (from the weighted average for all groups) for pipeline cost was 103.6%, whereas for independents it was only 19.1%.[22] As a further indication that the variation appears much higher for pipelines than independents, the table below, referred

[21]See testimony of Witness Field at Tr. 4345.

[22]See testimony of Witness Field at Tr. 4346.

to by the Examiner at page 38 of his Initial Decision, indicates that only 6.6% of the independent producers' volumes had costs (as computed by Witness Jones) which were more than 65% positive or 35% negative deviation from the average cost for independent producers, affiliates and pipelines—while 74.8% of the pipelines' volumes had costs with such variation. Moreover, the same data indicated that 84.0% of the independent producers' volumes had costs which were within 30% of the average cost—while 86.6% of the pipelines' volumes had costs which were *more than 30% above or below the average cost.*

Percentage of Volumes Which Deviated From The Weighted Average Cost For Independents, Affiliates and Pipelines Based On Witness Jones' Array Data

Deviation From The Weighted Average Cost For Independents, Affiliates and Pipelines	Pipelines Volumes (Mcf) (1)	Pipelines Percent of Total Volumes (2)	Independents Volumes (Mcf) (3)	Independents Percent of Total Volumes (4)
More Than 65% Positive Deviation	208,529,247	31.6	18,834,090	.4
More Than 35% Negative Deviation	285,245,364	43.2	273,977,711	6.2
Total		74.8		6.6
Within 30% Positive Or Negative Deviation	88,173,083	13.4	3,711,584,702	84.0
More than 30% Positive Or Negative Deviation	571,546,037	86.6	705,941,376	16.0
Total		100.0		100.0
Within 30% Positive Or Negative Deviation	48,508,743	7.4	2,710,241,616	61.4
More Than 20% Positive Or Negative Deviation	611,210,337	92.6	1,707,284,462	38.6
Total		100.0		100.0
Total Volumes For Each Group	659,719,120		4,417,526,078	

SOURCE: Column (1) - Page 1, Schedule 21, Exhibit No. 58
(2) - Volumes in Column (1) Divided by total volume in column (1) of 659,719,120 Mcf
(3) Pages 3 and 4, Schedule 21, Exhibit No. 58
(4) Volumes in Column (3) Divided by total volume in column (3) of 4,417,526,078 Mcf

* * *

[10564]

Excerpts from M.G.G. Reply Brief on Exceptions

[10849]

service method of regulation . . . maintained a healthy competitive atmosphere under which individual pipelines prospered," and he further found that "where circumstances truly warranted it the pipelines produced adequate supplies of their own gas. . . ."[15]

A. *Pipeline and Affiliate Production Has Grown and Prospered Under the Present Regulatory Policy.*

The evidence of record as found by the Examiner clearly demonstrates that pipelines and their affiliates have undertaken extensive and continually expanding activities in production of gas since the inception of cost-of-service regulation under the Natural Gas Act.

1. *Growth of pipeline production investment.*

The growth of gross investment by pipeline companies in production, exploration and development since 1940 has been steadily upward, increasing over ten times to 1961. Similarly, there has been a substantial increase in the gross production investment by affiliates.

[15] I.D. at 86.

[10850]

COMPOSITE GROSS PRODUCTION, EXPLORATION AND DEVELOPMENT INVESTMENT

Group 1 Pipeline Producers and Group 3 Affiliates*

Year	Group 1 Respondents	Group 3 Respondents	Group 1 & 3 Respondents
	Total Gross Investment		
1940	$ 105,288,000	$ 86,711,000	$ 191,999,000
1941	108,420,000	87,741,000	196,161,000
1942	116,019,000	88,374,000	204,393,000
1943	120,673,000	94,811,000	215,484,000
1944	151,572,000	97,895,000	249,467,000
1945	157,367,000	102,418,000	259,785,000
1946	172,963,000	107,847,000	280,810,000
1947	202,694,000	112,290,000	314,984,000
1948	204,454,000	116,429,000	320,883,000
1949	206,439,000	123,782,000	330,221,000
1950	212,794,000	144,846,000	357,640,000
1951	238,183,000	158,070,000	396,253,000
1952	258,460,000	169,644,000	428,104,000
1953	286,892,000	183,084,000	469,976,000
1954	315,204,000	228,923,000	544,127,000
1955	379,034,000	253,590,000	632,624,000
1956	430,470,000	282,969,000	713,439,000
1957	486,499,000	305,834,000	792,333,000
1958	549,606,000	329,710,000	879,316,000
1959	740,513,000	359,412,000	1,099,925,000
1960	814,570,000	397,750,000	1,212,320,000
1961	1,032,498,000	423,858,000	1,456,356,000
1962	982,686,000	441,741,000	1,424,427,000

*Ex. 21, Sch. 1 and 7; Ex. 61. The Group 1 respondents include all of the producing pipeline companies (as shown by the Pipeline Production Group, as listed in App. A to Ex. 21). The Group 3 respondents include all of the major on-system producing affiliates. (Names are listed in App. A to Ex. 21.)

[10851]

These data indicate quite clearly that the bulk of the pipeline companies' increase in production gross investment for the years 1940 through 1962 was the result of exploration and development activities. For producing pipelines and on-system affiliates of pipelines, the total gross investment increased from $191,999,000 in 1940 to $1,424,427,000 in 1962.

2. *Growth of exploration and development expenditures.*

Other than amounts capitalized in plant account resulting from exploration and development activities, the most significant indicator of the extent of such activities is the amount charged to current expense for exploration and de-

[10851]

velopment expenditures as provided in the Commission's Uniform System of Accounts. Such expense is allowed in ratemaking as a component of cost of service. Such costs are borne by the consumers in the amounts paid for gas service. The evidence shows as follows:

(Table Follows)

[10852]

COMPOSITE EXPLORATION AND DEVELOPMENT OPERATIONS COSTS AND EXPENSES

Reported by Group 1 and 3 Respondents
Years 1940-1962, Inclusive*

Year	Total for Group 1 Respondents	Total for Group 3 Respondents	Total for Group 1 & 3 Respondents
1940	$ 2,102,050	$ 1,275,444	$ 3,377,494
1941	2,458,315	1,728,476	4,186,791
1942	2,445,670	1,792,179	4,237,849
1943	2,783,488	1,551,523	4,335,011
1944	3,358,265	2,273,256	5,631,521
1945	3,755,830	3,120,823	6,876,653
1946	3,396,217	2,822,767	6,218,984
1947	5,484,659	3,677,265	9,161,924
1948	5,845,620	6,766,724	12,612,344
1949	6,194,506	5,615,759	11,810,265
1950	5,257,897	5,382,996	10,640,893
1951	5,720,942	6,546,469	12,267,411
1952	8,303,055	10,068,486	18,371,541
1953	11,373,444	10,632,544	22,005,988
1954	12,673,199	12,680,436	25,353,635
1955	15,373,381	16,742,463	32,115,844
1956	17,805,132	14,017,891	31,823,023
1957	26,198,689	21,151,708	47,350,397
1958	28,812,905	17,400,502	46,213,407
1959	26,683,902	23,536,316	50,220,218
1960	33,624,334	24,035,593	57,659,927
1961	27,732,569	23,320,655	51,053,224
1962	23,285,554	21,620,281	44,905,835

*Ex. No. 21, Sch. 9 (1940-1954); Ex. No. 5, Sch. 4, Sheet 1, line 4; Ex. No. 61, Col. 5 (1955-1962). See also Ex. No. 54, Sch. 7, Col. (e), line 23.

[10853]

Thus, in the important category of exploration and development expenses, the pipeline companies and their on-system affiliates subject to Commission cost-of-service regulation were spending more than 13 times as much money in 1962 for exploration and development as in 1940, having increased their expenditures from $3,377,494 in 1940 to $44,905,835 in 1962. Furthermore, the evidence re-

veals, with only few exceptions, an increasing amount expended each year by these companies for exploration and development activities.

3. *Growth of pipeline owned reserves and production.*

The total reserves owned by pipeline companies and affiliates of pipelines have also shown substantial growth since 1940.

(Table Follows)

[10854]

COMPOSITE OWNED GAS RESERVES
Group 1 and Group 3 Respondents*

Year	Group 1 Pipeline Co.'s Gas Reserves	Group 3 Affiliate Gas Reserves	Total Group 1 & 3 Gas Reserves
	- - - - - - - - - - - -	Mmcf (14.73)	- - - - - - - - - - - -
1940	9,909,639	2,558,434	12,468,073
1941	13,350,990	2,515,812	15,866,802
1942	13,712,289	2,971,216	16,683,505
1943	15,202,587	2,869,299	18,071,886
1944	15,356,176	3,315,406	18,671,582
1945	15,159,512	3,605,797	18,765,309
1946	15,773,930	3,504,380	19,278,310
1947	16,706,481	3,520,938	20,227,419
1948	15,397,607	3,657,310	19,054,917
1949	13,289,417	3,896,780	17,186,197
1950	13,014,355	4,603,732	17,618,087
1951	13,672,341	4,417,698	18,090,039
1952	15,539,479	4,861,407	20,400,886
1953	15,908,120	4,744,204	20,652,324
1954	15,545,287	5,315,527	20,860,814
1955	16,432,263	5,472,394	21,904,657
1956	20,191,589	5,604,746	25,796,335
1957	21,086,867	5,644,950	26,731,817
1958	21,662,588	5,485,804	27,148,392
1959	22,464,319	4,733,671	27,197,990
1960	24,234,153	4,910,731	29,144,884
1961	24,532,755	5,306,890	29,839,645
1962	23,516,543	5,307,638	28,824,181
1963	22,499,068	5,114,535	27,613,603
1964	21,564,234	5,128,220	26,692,454
1965	21,921,522	5,023,564	26,945,086

*Ex. No. 21, Sch. 1, col. 11 and Sch. 7, col. 6 (1940-1957); Ex. No. 6, p. 8 (1958-1965).

[10855]

Thus, the directly owned gas reserves reported by the pipeline respondents and their on-system affiliates increased from 12.468 trillion cubic feet in 1940 to 26.945 trillion cubic feet in 1965. During this period, while there are

years of little change, the overall trend has been generally upward.

At the same time that the directly owned gas reserves were increasing, the pipeline respondents and their affiliates were producing increasingly larger quantities of gas from their properties. The Municipal Gas Group evidence shows that the volumes of gas produced by pipeline companies and the Group 3 affiliated producers more than doubled from 412,712 Mmcf in 1940 to 1,237,433 Mmcf in 1965. (Ex. 21, Sch. 6; Ex. 6, p. 23, col. (c), lines 2-9, p. 25, col. (c), lines 3-10.) In addition to such production, some 5 trillion cubic feet or more of pipeline owned reserves were sold or transferred to others, little of which went to other pipelines, although a portion was transferred to affiliates (8R 971; 972-3). Substantial blocks of reserves formerly owned by Northern Natural Gas Company and Cities Service Gas Company were transferred to affiliates about 1952, but are now owned by non-affiliated producers. (8R 968; 973.)[16]

During the period 1940-1965, the producing pipelines maintained fairly consistent reserve to production ratios, at a high level. Staff Exhibit No. 6, page 3, shows that the Group 1 producing pipelines had a 27.9 reserve to production ratio in 1946, based on total company owned reserves, and in 1965 had a 24.2 ratio. This compares with the reserve to production ratio of 32.5 for the total United States in 1946 and 17.5 in 1965. (*Id.*) These figures are significant because they reveal that the pipeline companies owning reserves produced those reserves only to the extent deemed

[16]During this period between 1944 and the end of 1962, some 11 trillion cubic feet of gas were acquired by pipelines as producing properties. (Ex. No. 21, Sch. 2; Composite Summary, Vol. 1, page 17 (as corrected).)

[10856]

necessary or appropriate for their operations. If more pipeline owned gas were necessary or desirable, clearly the companies would have produced more from their existing reserves. The relative stability of the reserve to production ratios for the pipeline companies would thus indicate that the companies' ownership of such producing properties was approximately adequate for their requirements of this type of gas.

B. *Cost-of-Service Best Provides for the Development by Pipelines and Their Affiliates of Any New Needed Supplies of Gas.*

Individual cost-of-service pricing adequately compensates the exploration and development function of the pipeline company by permitting pipeline producers and affiliates the incentives inherent in allowing them actual production costs plus a fair rate of return on their individual overall investment. All "prudent" production costs are borne by the pipeline's consumers.[17] More specifically, in determining the rate of return for each individual pipeline company, the costs of successful wells are added to the rate base on which a return can be earned. The costs chargeable to unsuccessful wells are considered as an expense of doing business and an allowance for these expenses is granted.

But although the consumer underwrites the costs of discovery and development, he also shares in whatever benefits result from production. One benefit is the possibility of lower rates through, in part, the application to the transmission and delivery phase of the pipeline operation of any tax benefits spilling over after application of the tax benefits resulting from statutory depletion percentage and intangible well-drilling cost allowance to the production phase of the pipeline operation.

---

[17] For an excellent and thorough discussion of the mechanics of the cost-of-service method as it applies to pipeline production, *see* Pacific Gas and Electric Company Brief on Exceptions at pp. 3-11.

* * *

[10976]

* * *

As a form of regulation, there are certain advantages to both cost-of-service and area rates. Cost-of-service more

[10977]

closely equates the allowed rate to individual company costs; area rates encourage more efficient production. Advocates of each method of future regulation for pipeline production perhaps ourselves included, have stressed the administrative advantages of their preferred method. However, one substantive advantage of area rates is very important. Because area rates allow companies a greater promise of retaining the advantages of production efficiencies as increased immediate returns to their equity holders or deferred returns used for reinvestment, a lower overall area rate may provide a greater incentive to production than a higher individualized rate. This may be one reason why most pipelines seem to prefer area rates. Second, area rates avoid the need to individually cost production. However, it is our position that modified area rates should be adopted not because they are easier to administer than cost-of-service pricing, but because they provide a preferable mode of regulation.

II. THE EXCESSIVE COSTS EXPERIENCED BY SOME PIPELINE PRODUCERS, PLUS THE NEED TO PROVIDE INCENTIVE TO LOW COSTS PRODUCTION DEMANDS ADOPTION OF STAFF'S RECOMMEND MODIFIED AREA RATES.

Staff's recommendations in this case are premised upon the factual demonstration of excessive cost incurrence by some pipelines for production from company-owned properties. In fact,

[10978]

the costs of some pipeline producers have been so high that aggregate pipeline production costs have been in excess of

aggregate independent producer costs, despite large investments by some pipelines of early vintage supplies in the low cost Hugoton-Panhandle field. For a factual demonstration of high pipeline production costs, we respectfully refer the Commission to the Initial Staff Brief to the Presiding Examiner, pp. 23-38, and the Staff Brief on Exceptions, pp. 20-32.

The fact of regulation, warranted by ineffective competition, does not lessen the jusitification for imposing the normal limitation of the market place that limits consumer charges to a competitive cost standard. Moreover, because under cost-of-service pricing pipelines cannot anticipate retaining the profits up to aggregate industry cost levels from low cost lease acquisitions or development, the failure to adopt group pricing standards to Phase I production may give less incentive to expanded pipeline production than is warranted. Under cost-of-service regulation the natural gas consumer must bear the risk of having to apy prices for gas far in excess of aggregate industry cost levels without receiving the benefit of providing increased inventives to pipeline production.

We believe the record amply demonstrates that the reasons for pipelines' experienced high production costs are not due to

[10979]

factors inherent to piepline production or to achieving special benefits justified by their transmission operations. Rather, these high total costs have resulted from high lease acquisition costs and inefficient production operations. Both have been encouraged under cost-of-service regulation. Thus, we cannot justify a continued allowance of these high costs for production from pipelines' future reserve acquisitions.

[10979]

A. *The High Costs of Pipeline Production Have Been Amply Demonstrated on this Record.*

Some parties, but principally El Paso, have attempted to demonstrate either that pipelines have not experienced high production costs or that such production ocsts are warranted, In the case of El Paso, such contentions are directed to refuting the need for application of uniform industry production costs to pipeline production.[1] El Paso, pp. 40-45, 50-59. Other

---

[1] While El Paso argues that pipeline production costs have not been excessive under cost of service regulation, the Municipal Gas Group, the other major proponent of continued cost of service regulation, states that it is the "significant differences, indicated on the record, between pipeline production by affiliated producers and independent producers in purposes, operations, and costs * * *" which warrant its continuation. Municipal Gas Group. p. 6 [footnote omitted]. Compare E. Paso, pp. 16-25.

Citations to briefs on exceptions will be as above throughout without additional reference. *E.g.*, El Paso, 3-8 [footnote continued.]

[10996]

We hasten to add that we do not mean to imply that in a transmission company rate case the Commission should not give full consideration to all factors relevant to setting company rates of return. In addition to capital costs, the Commission considers individual companies' capital structures, management efficiency, and various other factors. *E.g., Panhandle Eastern Pipe Line Company*, 40 FPC 98, 104-105 (1968); *Natural Gas Pipeline Company of America*, 40 FPC 81, 93-94 (1968). Should the Commission decide to impute the new gas area rate, which itself considers non-cost factors, we would generally oppose including special production incentives as part of a pipeline rate of return. See *El Paso Natural Gas Company*, 28 FPC 688, 695-697 (1962); *Southern Natural Gas Company*, 29 FPC 323, 335-338 (1963). This is especially true, since the opportunity to recover greater

[10997]

profits under area pricing disproportionately benefits pipelines due to the underlying stability of their overall investment, which acts as a floor on potential losses, combined with the disproportionate benefit their shareholders would receive from additional profits because of their typically highly leveraged capital structures. (See 28/3064: 12-3065:2). But the point is that we recognize that other factors besides capital costs will and should be taken into consideration in determining overall company rates of return. We think it unwise for the Commission to here predetermine apart from specific pipeline rate cases the applicable rate of return with regard to any particular portion of a pipeline's investment.

* * *

[10998]

Consolidated argues that pipeline producers are entitled to a higher return on production, because the shareholders bear the risk under area rate pricing of a piepline failing to meet the industry cost standard and becaseu "* * * the principal uncertainty in the production business is an operating risk–the risk of drilling a dry hole or a noncommercial well." Consolidated, pp. 12-13. The former argument is answered on pp. 60-62 of our Staff Brief on Exceptions. Basically the argument ignores the offsetting advantage to a regulated company with reasonably assured minimal company earnings of being able to earn far greater than otherwise allowed returns. While there may be additional "risk" to switching to area rates, most pipeline companies seem to prefer that risk to a relatively more

[10999]

assured, but lower, income.

aggregate independent producer costs, despite large investments by some pipelines of early vintage supplies in the low cost Hugoton-Panhandle field. For a factual demonstration of high pipeline production costs, we respectfully refer the Commission to the Initial Staff Brief to the Presiding Examiner, pp. 23-38, and the Staff Brief on Exceptions, pp. 20-32.

The fact of regulation, warranted by ineffective competition, does not lessen the jusitification for imposing the normal limitation of the market place that limits consumer charges to a competitive cost standard. Moreover, because under cost-of-service pricing pipelines cannot anticipate retaining the profits up to aggregate industry cost levels from low cost lease acquisitions or development, the failure to adopt group pricing standards to Phase I production may give less incentive to expanded pipeline production than is warranted. Under cost-of-service regulation the natural gas consumer must bear the risk of having to apy prices for gas far in excess of aggregate industry cost levels without receiving the benefit of providing increased inventives to pipeline production.

We believe the record amply demonstrates that the reasons for pipelines' experienced high production costs are not due to

[10979]

factors inherent to piepline production or to achieving special benefits justified by their transmission operations. Rather, these high total costs have resulted from high lease acquisition costs and inefficient production operations. Both have been encouraged under cost-of-service regulation. Thus, we cannot justify a continued allowance of these high costs for production from pipelines' future reserve acquisitions.

[10979]

A. *The High Costs of Pipeline Production Have Been Amply Demonstrated on this Record.*

Some parties, but principally El Paso, have attempted to demonstrate either that pipelines have not experienced high production costs or that such production ocsts are warranted, In the case of El Paso, such contentions are directed to refuting the need for application of uniform industry production costs to pipeline production.[1] El Paso, pp. 40-45, 50-59. Other

---

[1] While El Paso argues that pipeline production costs have not been excessive under cost of service regulation, the Municipal Gas Group, the other major proponent of continued cost of service regulation, states that it is the "significant differences, indicated on the record, between pipeline production by affiliated producers and independent producers in purposes, operations, and costs * * *" which warrant its continuation. Municipal Gas Group. p. 6 [footnote omitted]. Compare E. Paso, pp. 16-25.

Citations to briefs on exceptions will be as above throughout without additional reference. *E.g.*, El Paso, 3-8 [footnote continued.]

[10996]

We hasten to add that we do not mean to imply that in a transmission company rate case the Commission should not give full consideration to all factors relevant to setting company rates of return. In addition to capital costs, the Commission considers individual companies' capital structures, management efficiency, and various other factors. *E.g., Panhandle Eastern Pipe Line Company*, 40 FPC 98, 104-105 (1968); *Natural Gas Pipeline Company of America*, 40 FPC 81, 93-94 (1968). Should the Commission decide to impute the new gas area rate, which itself considers noncost factors, we would generally oppose including special production incentives as part of a pipeline rate of return. See *El Paso Natural Gas Company*, 28 FPC 688, 695-697 (1962); *Southern Natural Gas Company*, 29 FPC 323, 335-338 (1963). This is especially true, since the opportunity to recover greater

[10997]

profits under area pricing disproportionately benefits pipelines due to the underlying stability of their overall investment, which acts as a floor on potential losses, combined with the disproportionate benefit their shareholders would receive from additional profits because of their typically highly leveraged capital structures. (See 28/3064: 12-3065:2). But the point is that we recognize that other factors besides capital costs will and should be taken into consideration in determining overall company rates of return. We think it unwise for the Commission to here predetermine apart from specific pipeline rate cases the applicable rate of return with regard to any particular portion of a pipeline's investment.

* * *

[10998]

Consolidated argues that pipeline producers are entitled to a higher return on production, because the shareholders bear the risk under area rate pricing of a piepline failing to meet the industry cost standard and becaseu "* * * the principal uncertainty in the production business is an operating risk–the risk of drilling a dry hole or a noncommercial well." Consolidated, pp. 12-13. The former argument is answered on pp. 60-62 of our Staff Brief on Exceptions. Basically the argument ignores the offsetting advantage to a regulated company with reasonably assured minimal company earnings of being able to earn far greater than otherwise allowed returns. While there may be additional "risk" to switching to area rates, most pipeline companies seem to prefer that risk to a relatively more

[10999]

assured, but lower, income.

[11001]

C. *Pipeline Producers Should Not Be Allowed Phantom Taxes to Subsidize Their Gas Production Function.*

In pipeline rate cases, the Commission follows what is termed an "actual taxes paid" standard for determining Federal income tax allowances. Such allowance is based upon estimates of the actual amounts of tax a company will have to pay to the Federal Treasury on its allowed cost-of-service. The allowance is derived by adjusting the allowed return, based upon test year experience, for applicable adjustments which would be made for tax purposes. Examples of such adjustments would be adjusting the book depreciation to allowed tax depreciation. For companies having production, additional adjustments are made to substitute the allowed tax deductions for depletion and intangible drilling costs, which would almost always be far greater than the applicable book deductions. Thus, the tax ultimately allowed reflects the applicable differences between book and tax accounting as applied to the company's allowed return. *E.g., Southern Natural Gas Company*, 29 FPC 323, 357-358 (1963), petition for review dismissed, CA-3, No. 14,399 (November 23, 1963). For companies whose production operations are conducted through a separate producing

[11002]

affiliation, the principle is the same.[1] The total corporate structure is divided into "regulated" and "unregulated" companies. Tax deductions attributable to income from regulated companies are initially used to offset taxes which would be paid on the return generated from regulated (i.e., transmission) activities. In addition, if the companies in the consolidated group whose activities are largelv or totally unregulated generate sufficient tax deductions to totally eliminate taxes paid on unregulated functions, then such tax deductions are used to further offset taxes which would be paid on regulated income. *Cities Service Gas Company*, 30 FPC 158 (1963), set aside sub. nom., *Cities Service Gas Company v. FPC*, 337 F.2d 97 (CA-10, 1964), but approved in *FPC v. United Gas Pipe Line*

[1] Union Producing Company claims because of allocation problems and otherwise, determining tax allowances for produced gas is "virtually, if not wholly, impossible." Union, pp. 17-21 at p. 18 (original in italics). Despite Union's allegations, the Commission has successfully adjusted tax deductions which may vary from cost-of-service computations. We see no difficulty in its doing so in the future. The main alleged disability in deriving a tax allowance appears to stem from the fact that tax depletion is a variable, that it is computed on a property basis and that the amount of the deduction may vary depending upon the price received for the gas and other factors. We do not pretend that a particular company will experience actual costs in total or for any particular item exactly equal to its cost-of-service; this does not prevent using an estimated cost based upon a test year cost-of-service to reflect a reasonably accurate estimate of future costs.

[11003]

Company, 386 U.S. 237 (1967).[1]

The effect of the "actual taxes paid" doctrine has been to reduce the tax allowance on the transmission segment of a company's business beneath what it would otherwise have been had there not been production tax deductions available in excess of production return. This is nothing more than an exercise of "the power and the duty of the Commission to limit cost of services to real expenses."[2] The Pipeline Production Group states, "What evidence there is in the record suggests that the pipeline producers on aggregate had a positive tax on the production functions in 1962." Pipeline Production

[1] The Commission has before it the question of allocating the deductions generated by nonregulated income between jurisdictional and nonjurisdictional components of a company's business. *FPC v. United Gas Pipe Line Company*, 393 U.S. 71 (1968). Where the Commission first determines a total applicable cost for all volumes of gas, this would appear to automatically result in the required allocation. But in any event, however the secondary allocation is made, there should be no question of different treatment for excess tax deductions above return on production for companies separating their production and transmission functions into separate corporate entities and those acting as a single entity. To allow such difference would allow corporate form to control rate treatment. *United Gas Improvement Company v. Continental Oil Company*, 381 U.S. 392, 395-404 (1965).

[2] *F.P.C. v. United Gas Pipe Co., supra*, 386 U.S. at 245.

[11004]

Group, p. 60.[1] Amerada suggests that, since future administration of the tax laws is susceptible to change, one cannot tell what the properly allowed future Federal income tax expense will be. Amerada, pp. 4-5 We agree that by definition the future is unknown, but to the extent that the past is prologue to the future, we point out that to our knowledge there has never been a pipeline rate case where a positive tax on production has been demonstrated or allowed. However, we emphasize that our proposal is to continue to allow respondents their actual taxes payable, whether the tax on production, if separately computed, would be positive or negative. Therefore, should the production function in fact generate positive taxes, respondents would not be hurt by adoption of our proposal. However, should future pipeline production activities generate greater tax deductions than the applicable tax on production, consumers would not be deprived of long sought-for benefits

---

[1] The Pipeline Production Group cites Exhibits 70 and 71 to demonstrate both that there might be a positive tax paid on production (p. 60) and that "elimination of tax deduction benefits would reduce the effective rate of return earned under area rates from 11.29% to 5.16%." (p. 62) Exhibit 60 fails to show applicable tax deductions; Exhibit 71, apart from being highly conjectural, fails to reflect effects of replacement of reserves and of growth on Federal income tax calculations.

[11005]

merely because of a switch in the mode of costing pipeline production to aggregate production costs rather than individual company costs.[1]

[1]Because we would allow companies their actual amounts of tax, apart from demonstrating that significant tax deductions on production unrelated to cost do exist, it is irrelevant to our position to quantify whether there are "negative" taxes or the amount of such negative taxes. Respondents, for varying reasons, supported application to pipeline production of the zero tax allowance heretofore utilized in area rate cases. The position during hearing of the Pipeline Production Group was that on aggregate there would not be negative taxes. See text. Witnesses for Tennessee, and also for Tenneco Oil Company, testified that "benefits from tax deduction spillover related to production operations . . . can be very substantial" (38(1)/4065: 4-8), but that these benefits should be able to be retained by pipelines to allow them to compete with independent producers. (38(1)/4057:17-24; 4049:20-25). Witness Larson for Consolidated testified that, while there are substantial tax deductions generated by production of a nature not available to other industries it cannot be determined from this record whether the production function generates "negative" taxes. 38(1)/4040:16-4044:19; 38(2)/4365:23-4366:23). However, assuming that it does, Consolidated's position is that such tax losses should be able to be retained by the pipelines. 38(1)/3985: 18-3988:18). Staff had moved to strike Pipeline Production Group tax exhibits and certain other evidence as not being probative, since they were not related to actual return data. Given the state of the record, Staff and other parties agreed:

"(F)irst, that there may be disagreement among the parties and/or witnesses as to whether there is or would be a positive or negative tax on pipeline or independent producer production activities. Second, . . . that an actual positive or negative tax liability can not be determined from the data available in this record . . . ." Third, that tax evidence in the record is merely "illustrative" of the significance of oil and gas tax deductions or offsets to those deductions. 47/ 5420:5-5436: 26 at 5420:5-26)

[11006]

The Pipeline Production Group at page 61 of its brief states:

> The incentive of pipeline producers to seek and develop new gas reserves in competition with other producers would be seriously undermined if they were denied the benefit of income tax deductions resulting from production investment or losses. Such deductions can in no sense be considered a windfall, but are contemplated by the area rate method.

Again, on page 62 the Pipeline Production Group states:

> The Examiner has recognized the competitive penalty imposed on pipeline producers by flow-through of tax benefits under cost of service (p. 91). There appears to be no reason why pipeline producers from an incentive standpoint should be treated differently from independent producers.

Protestations notwithstanding, it is clear that the Pipeline Production Group and other respondents view imputation of a zero production tax as a means of avoiding the Commission's "actual taxes paid" policy and of securing a noncost rate allowance. It may be correct that the independent producer area rate is overstated insofar as it does not allow for a negative tax credit or consideration of tax losses generated by the production function in the area rate of return component. But, regardless, the fact that independent producers may receive such noncost allowance in no way justifies granting an equally

[11007]

unjustified allowance to pipeline producers. There is no indication that the Commission in the area rate cases intended to use negative taxes as a rate allowance adding to rate of return. This being the case, there is no reason to compute the tax allowance in pipeline rate cases in such a way to insure that the tax imputed to the production function equals

zero or any other amount specified in relevant area rate proceedings. If a rate additive is justified, and we see no evidence that it is, it should be done directly through the rate of return allowance ultimately ordered.[1]

[1] We reject the implication on page 61 of the Pipeline Production Brief that negative taxes from production result because pipelines may be losing money. The tax deductions in question are of such a nature that they do not necessarily generate negative taxes because of book losses. Moreover, as computed in actual rate cases, the tax allowance is based upon the assumed allowable rate of return.

[11008]

III. THE PIPELINE RATE SHOULD NOT BE INFLATED FOR SPECULATIVE AND UNQUANTIFIED INTANGIBLE VALUES.

A. There Is No Justification For Increasing the Pipeline Rate of Return or Rate Allowance to Provide Special "Inventives" For Increased Supply.

Pipeline respondents and producer interveners allege general supply inadequacy. They claim that such inadequacy demands "encouraging" all producers to find additional supply. *e.g.*, Amerada, p. 10; Consolidated, p. 13; Pipeline Production Group, pp. 13-21; Tennessee, pp. 3-4. The Pipeline Production Group states, "Gas supply adequacy is the overriding issue in Phase I, and we do not believe that the Commission can safely afford to select an unsatisfactory, experimental approach in prescribing pipeline producer rate allowances, in today's gas supply situation." Pipeline Production Group, p. 21.

The "overriding issue" in this proceeding is not gas supply, but rather the best mode of pricing Phase I pipeline production with regard to the Commission's total responsibilities. Even assuming respondents' contentions with regard to supply are correct, this does not answer the question of how high the allowed rates for their own produced gas should be. Staff agrees with the position

[11009]

of nearly all the major pipelines that a form of economics pricing which allows pipelines to retain the benefits of efficient production affords greater production incentives than cost-of-service pricing, even though the latter might be set at a higher individual rate level. We would allow the pipelines the same production costs allowed independent producers including a royalty allowance based upon the higher independent producer rate and all special rate design incentives or other rate adjustments allowed independent producers. Therefore, the only real difference between Staff and respondents is that we would not set their production rate of return far above their capital costs unless such assumed higher capital costs for production were specifically considered in setting the applicable transmission rate of return, nor would we allow increases in pipeline's rate of return through ignoring negative taxes generated by the production function.

To the extent ultimate markets will support higher gas prices, and there is requisite demand, we do not doubt the general proposition that if enough of an additional price is given that price will yield additional supply.

[11010]

However, this factor in and of itself is not a justification for additional rate increases. Unless it assumed that affording respondents increased revenues is by definition advantageous, nothing in these proceedings could justify increasing pipeline equity returns on the production properties to what in specific cases may be above 20% and as high as 40% because of claims of supply inadequacy. *City of Detroit v. F.P.C.*, 230 F.2d 810, 817-818 (CADC), *certiorari denied*, 352 U.S. 829 (1956). In short, we reject the notion that the mere claim of supply shortages can be used to circumvent or defeat all regulatory controls. *Accord*, Decision, pp. 38-39.

Pipeline respondents overlook the fact, found by the Examiner, that compared with independent producers, their production is relatively insignificant.

> Pipelines (not counting affiliates) account for approximately 5.5 percent of total U.S. production and 7.5 percent of U.S. reserves. While their production is important, compared with major independents, pipeline producers tend to be small and "it is to be doubted that pipeline companies can be relied upon for a general oil and gas supply assurance." Decision, p. 38, n. 1, quoting 38(1)/4131:22-4133:3.

[11270]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 568

Pipeline Production Area Rate Proceeding (Phase I)	))	Docket No. RP66-24

STATEMENT OF POLICY
AS TO PRICING FOR NEW GAS PRODUCED
BY PIPELINES AND PIPELINE AFFILIATES

Issued: October 7, 1969

DC-42

[11271]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Pipeline Production Area Rate Proceeding (Phase I)	))	Docket No. RP66-24

OPINION NO. 568

APPEARANCES

Charles E. McGee and *John T. Ketcham* for Algonquin Gas Transmission Company

D. Pierre G. Cameron, Jr. for Kentucky Gas Transmission Company, United Fuel Gas Company, Manufacturers Light and Heat Company, The Preston Oil Company, Ohio Fuel Gas Company, Atlantic Seaborad Corporation and Cumberland and Allegheny Gas Company

Charles V. Wheeler and *Daniel R. Hopkins* for Cities Service Gas Company

C. C. Cammack, R. J. Leithead and *Graydon D. Luthey*

for Cities Service Oil Company and Columbian Fuel Corporation

James L. White, Raymond N. Shibley and *William Warfield Ross* for Colorado Interstate Gas Company

James L. White for Colorado Oil and Gas Company

Thomas A. White, Lawrence L. Gray, Norman A. Flanigam, Charles R. Brown, Kenneth M. Waters and *H. B. Griffith* for Consolidated Gas Supply Corporation

G. Scott Cuming, Charles V. Shannon, David T. Burleson, C. Frank Reifsnyder and *Stanley S. Harris* for El Paso Natural Gas Company

Carl Illig, Jesse H. Foster, Jr., Martin N. Erck, James K. Scholler and *Robert L. Norris* for Humble Gas Transmission Company and Humble Oil & Refining Company

[11272]

Donald I. Moritz and *John T. Brown* for Kentucky-West Virginia Gas Company

Manuel J. Edling, Jr., Richard B. Williams, John W. Scott and *Louis L. Da Pra* for Lone Star Gas Company and Lone Star Gathering Company

Raymond N. Shibley and *William Warfield Ross* for Lone Star Gas Company

Charles V. Shannon, Louis Flax and *Paul S. Davis* for Michigan Wisconsin Pipe Line Company

W. C. Braden, Jr. and *L. R. Pankonien* for Midwestern Gas Transmission Company

William W. Bedwell and *James H. Wuller* for Mississippi River Transmission Corporation

Charles McDugald, William Brackett, Paul Goldstein, Raymond Peterson, Raymond N. Shibley and *William Warfield Ross* for Natural Gas Pipeline Company of America

F. Vinson Roach, Jack C. Osborne, Walter E. Gallagher, Frank J. Duffy, Raymond N. Shibley and *William Warfield Ross* for Northern Natural Gas Company

[11272]

John L. Arrington, Jr. for Oklahoma Natural Gas Gathering Corporation

Richard H. Peterson, Malcolm H. Furbush, John A. Sproul and *John S. Cooper* for Pacific Gas Transmission Company

William J. LeBuhn, Raymond N. Shibley and *William Warfield Ross* for Panhandle Eastern Pipe Line Company

Hugh J. Morgan, Jr., William S. Tarver, Lewis Carroll, Peter G. Smith, Raymond N. Shibley and *William Warfield Ross* for Southern Natural Gas Company

Sherman S. Poland, Clinton B. Fascett and *Bradford Ross* for South Texas Natural Gas Gathering Company

[11273]

D. Pierre G. Cameron, Jr. and *Donald M. Ochacher* for The Preston Oil Company

Joseph F. Weiler, Jack D. Head and *Keith M. Pyburn* for La Gloria Oil and Gas Company

Barclay D. McMillen, John H. Watson and *Robert E. Shaw* for Tenneco Oil Company

Harry S. Littman, Jack Werner, W. C. Braden, Jr., Roy Alletag, Robert E. Shaw, Richard Littrell, Harold Talisman and *Melvin Richter* for Tennessee Gas Pipeline Company a Division of Tenneco, Inc.

Jack D. Head, Joseph F. Weiler and *Keith M. Pyburn* for Texas Eastern Transmission Corporation

Justin R. Wolf, Stanley Wanger and *Elliott G. Flowers* for Texas Gas Pipe Line Corporation

Christopher T. Boland, George J. Meiburger, Robert O. Koch, Raymond N. Shibley and *William Warfield Ross* for Texas Gas Transmission Corporation

William H. Davidson, Jr., Thomas F. Ryan, Ray V. Lofton, Jr., Raymond N. Shibley and William *Warfield Ross* for Transcontinental Gas Pipe Line Corporation

James W. McCartney for Transwestern Pipeline Company

Leland F. Cadenhead, Raymond N. Shibley and *William Warfield Ross* for Trunkline Gas Company

Baine P. Kerr for Pennzoil-United, Inc.

Saunders Gregg, W.O. Crain, Thomas Fletcher, and *J.C. Ohrt* for Union Producing Company

D. Pierre G. Cameron, Jr., Raymond N. Shibley and *William Warfield Ross* for United Fuel Gas Company

Raymond N. Shibley, William Warfield Ross and *Saunders Gregg* for United Gas Pipe Line Company

[11274]

Edwin S. Nail for Amerada Petroleum Corporation

Charles F. Wheatley, Mr., Mathias M. Mattern, Leonard Campbell, Max Zall, and *Reuben Goldberg* for American Public Gas Association consisting of gas distributors within the States of Alabama, Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Nebraska, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia and Washington; and also for the City of Chicago, the City and County of Denver, and Memphis Light, Gas and Water Division

Stuart J. Scott and *Bernard A. Foster, Jr;* for The Atlantic Richfield Company

John W. Glendening, Jr. and *John S. Schmid* for the New England Intervenors comprising: The Berkshire Gas Company, Boston Gas Company, The Bridgeport Gas Company, Bristol and Warren Gas Company, Brockton Taunton Gas Company, Buzzards Bay Gas Company, Cambridge Gas Company, Central Massachusetts Gas Company, Concord Natural Gas Corporation, The Connecticut Gas Company, Fall River Gas Company, Fitchburg Gas and Electric Light

[11274]

Company, Gas Service, Inc., The Greenwich Gas Company, The Hartford Electric Light Company, Haverhill Gas Company, City of Holyoke, Massachusetts Gas and Electric Department, Lawrence Gas Company, Lowell Gas Company, Lynn Gas Company, Manchester Gas Company, Mystic Valley Gas Company, New Bedford Gas and Edison Light Company,The New Britain Gas Light Company, New Haven Gas Company, The Newport Gas Light Company, North Attleboro Gas Company, Northampton Gas Light Company, North Shore Gas Company, City of Norwich, Department of Public Utilities, Norwood Gas Company, The Pequot Gas Company, Providence Gas Company, South County Gas Company, Hartford Gas Company, Springfield Gas Light Company, Tiverton Gas Company, Valley Gas Company, Wachusett Gas Company, City of Westfield Gas and Electric Light Department, Worcester Gas Light Company

Edward F. Russell, Harry G. Hill, Jr. and *Barbara M. Suchow* for the Brooklyn Union Gas Company

Mary Moran Pajalich, J. Calvin Simpson, Sheldon Rosenthal and *Lawrence Q. Garcia* for the People of the State of California and the Public Utilities Commission of the State of California

[11275]

Walter A. Bossert, Jr., Morrell S. Lockhart and *Theodore J. Carlson* for Central Hudson Gas & Electric Corporation

Charles V. O'Hern, Jr., for Central Illinois Light Company

Martin Hogan, Raymond F. Simon, Mathias M. Mattern, Charles F. Wheatley, Jr., Leonard Campbell, Max Zall, and *Reuben Goldberg* for City of Chicago

Robert Lee Kessler for Public Utilities Commission of the State of Colorado, and The State of Colorado, *ex rel.*

James O. Malley, Jr., H.G. Skinner and *Ronald E. Jones* for Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation and Orange and Rockland Utilities, Inc.

Bruce R. Merrill, Joseph C. Johnson and *Tom Burton* for Continental Oil Company

Warren M. Sparks and *Donald R. Arnett* for Gulf Oil Corporation, Kerr-McGee Corporation and Warren Petroleum Corporation.

Robert W. Henderson and *Donald K. Young* for Hunt Oil Company

Robert S. Hunt and *Peter B. Fazio, Jr.* for Illinois Power Company

Harry L. Albrecht for Independent Natural Gas Association of America, The Pipeline Division

Jack F. Kenney for Iowa Public Service Company

Robert W. Russell and *Roger Arnebergh* for City of Los Angeles

Donald M. Ochacher for Columbia Gas Systems Service Corporation

Edward M. Barrett, Bertram D. Moll and *Morton L. Simons* for Long Island Lighting Company

Jack Fariss for Marathon Oil Company

George C. Pardee for Metropolitan Utilities District of Omaha

Richard M. Merriman for Michigan Gas Utilities Company

[11276]

T.P. Hamill, R.D. Haworth, J.T. McMahon, and *Charles S. Chester* for Mobil Oil Corporation and Northern Natural Gas Producing Company

John W. Scott and *Louis L. Da Pra* for Minnesota Natural Gas Company

Payton G. Bowman, III for Mississippi Valley Gas Company

Frederick T. Searls, Malcolm H. Furbush, Stanley T. Skinner, John S. Cooper and *Sanford M. Skaggs* for Pacific Gas and Electric Company

[11276]

K. R. Edsall, H. L. Goth, Robert Salter and *William H. Owens* for Pacific Lighting Service and Supply Company, Southern California Gas Company, and Southern Counties Gas Company of California.

J. P. Hammond, T. C. McCorkle and *William H. Henderson* for Pan American Petroleum Corporation

Robert W. Maris, William T. Coleman, Jr. and *Thomas K. Gilhool* for Philadelphia Gas Works Division of the United Gas Improvement Company

Kenneth Heady and *John R. Rebman* for Phillips Petroleum Company

E. A. Stansfield for Public Service Company of Colorado

J. Harry Mulhern, Edward S. Kirby and *James R. Lacey* for Public Service Electric and Gas Company

Sherman Chickering, C. Hayden Ames, Stanley Jewel and *Donald J. Richardson, Jr.* for San Diego Gas & Electric Company

Robert R. Laughead and *Thomas N. O'Connor* for City and County of San Francisco

Oliver L. Stone and *Thomas G. Johnson* for Shell Oil Company

Paul Davis and *Charles E. McGee* for Sinclair Oil & Gas Company

Richard J. Dent for Skelly Oil Company

Phillip D. Endom for Sun Oil Company

[11277]

William T. Kilbourne, Herbert W. Varner and *Homer J. Penn* for Superior Oil Company

William K. Tell, Jr. and *William R. Slye* for Texaco Inc.

John Davenport for Texas Independent Producers & Royalty Owners Association

William E. Torkelson and *Clarence B. Sorensen* for Public Service Commission of Wisconsin

Robert B. McConnell and *Bronson C. LaRollette* for State of Wisconsin

Richard M. DiValerio and *W. J. Scott* for United Natural Gas Company, Pennsylvania Gas Company, Iroquois Gas Corporation and Sylvania Corporation

Louis R. Reif for National Fuel Gas Company and Iroquois Gas Corporation

Raymond N. Shibley and *William Warfield Ross* for Kansas-Nebraska Natural Gas Company, Inc.

Arnold D. Berkeley, Harry Gollomp, Kenneth H. Plumb, Lloyd E. Dietrich, Robert A. Jablon, A. Michael Cappalletti and *Robert J. Andrade* for the Staff of the Federal Power Commission

[11278]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION
(18 CFR § 2.66)

POLICY STATEMENT: AREA RATES: PIPELINES (Production);
COST OF SERVICE (Taxation); ACCOUNTING (Pipeline Production);
RATE SCHEDULE (Filing); RATES (Pipeline)

Before Commissioners: John N. Nassikas, Chairman;
L. J. O'Connor, Jr., Carl E. Bagge,
John A. Carver, Jr., and Albert B. Brooke, Jr.

Pipeline Production)
Area Rate Proceeding) Docket No. RP66-24
Phase I)

[11278]

OPINION NO. 568

STATEMENT OF POLICY
AS TO PRICING OF NEW GAS PRODUCED
BY PIPELINES AND PIPELINE AFFILIATES

(Issued October 7, 1969)

O'CONNOR, Commissioner:

1. This is an investigation to determine whether in pipeline rate making the Commission should depart from the cost-of-service method and adopt an area method for pricing gas produced by pipelines or acquired by them from their affiliates.

2. The investigation was initiated by the Commission's order of June 29, 1964, in the *Hugoton-Anadarko* area proceeding, AR64-1, *et al.*, 31 FPC 1595. After certain direct evidence had been submitted, upon Staff's motion the Commission, on April 13, 1966, severed the *Pipeline Production* proceeding, 35 FPC 497, from *Hugoton-Anadarko* saying that the evidence indicated that this area was not typical of the country as a whole. The Commission noted that "whether the Commission may or should depart from the cost-of-service method in fixing the price of pipeline produced gas is the precise issue to be determined in this investigation." It ordered that a separate proceeding be instituted "to determine the proper method to be used by the Commission in pricing natural gas produced by pipelines or acquired by them from their affiliated producers" and joined a list of pipeline companies as parties-respondent. The Commission required that Phase I, which is now before the Commission comprise:

[11279]

"What is the most appropriate pricing method to be applied to natural gas utilized in a pipeline's interstate system which is produced by the pipeline or its affiliated pro-

ducing company from leases acquired after
the date of determination of this Issue."

3. By order of May 25, 1966 the Commission joined a group of producer companies that are affiliates of the pipeline respondents and on December 5, 1966, denied a motion by a pipeline production group (Pipeline Group) 1/ for an informal rule making proceeding.

4. After a prehearing conference the hearing began on September 27, 1967, and was concluded on April 2, 1968, and the decision of Presiding Examiner Allen C. Lande was issued March 3, 1969.

5. Exceptions were filed by the Pipeline Group, El Paso Natural Gas Company, A Municipal Gas Group (Municipal Group), Consolidated Gas Supply Corporation and Public Service Electric and Gas Company (Consolidated and PSEG) Union Producing Company, Tenneco Oil Company, Cities Service Oil Company, Tennessee Gas Pipeline Company (Tennessee), Southern California Gas Company, Southern Counties Gas Company of California and Pacific Lighting

---

1/ Cities Service Gas Company, Humble Gas Transmission Corporation, Colorado Interstate Gas Company, Kansas-Nebraska Natural Gas Company, Lone Star Gas Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipeline Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corp., Trunkline Gas Company, United Fuel Gas Company, and United Gas Pipeline Company.

Service Company (Southern California Companies), Pacific Gas amd Electric Company (PG&E), a group of Producer Intervenors, 2/ Humble Oil & Refining Company and Humble Gas Transmission Company (Humble), The People of the State of California and the Public Utilities Commission of the State of California (California), and the Staff of this Commission. Briefs opposing exceptions were filed by the

[11279]

Pipeline Group, El Paso, the Municipal Group, Consolidated and others (Consolidated Group), [3] Tenneco Oil, Cities Service Oil, Union, California, and our Staff. As the Examiner noted, four general positions have been advanced. The Pipeline Group and certain others have advocated use of the same area rate as for independent producers. El Paso and the Municipal Group have advocated a continuation of the Commission's present cost-of-service policy. Consolidated has advocated cost-of-service rates solely for Appalachia, but unmodified area rates for the other areas. The Staff has advocated area rates but with individual rate of return and Federal income tax components.

6. The Examiner, generally, would retain the traditional cost-of-service approach. However, he would permit the pipeline producers (known as Group 1) to share the Federal Income Tax benefits 50-50 with consumers. The on-system pipeline affiliates (Group 3) and the off-system pipeline affiliates (Group 4) would be allowed for on-system sales the applicable area rate for 10 percent of their new gas production, but the remainder of their on-system sales volumes would be subject to cost-of-service, without benefit of any tax sharing. New production sold off-system would receive the area or the in-line rate.

---

[2] Amerada Petroleum Corporation, Continental Oil Company, Mobil Oil Corporation, Pan American Petroleum Corporation, Shell Oil Company, and Texaco Inc.

[3] Iroquois Gas Corporation, Pennsylvania Gas Company, United Natural Gas Company and Kentucky West Virginia Gas Company.

[11281]

7. This is a turning point in the regulation of pipelines owning their own reserves, but it follows closely upon the development of area regulation for the independent producers and a changing picture in the gas supply situation

as shown by the record and other facts coming to our attention. In the light of an apparent gas shortage we are concerned whether the pipelines will make an increased effort to explore for and develop new gas reserves. We are also concerned whether new gas supplies will be available to the consumers of gas served by the long pipelines. To attain these ends it may be incumbent upon us to modify traditional approaches to regulation with respect to pipelines production in order to provide a regulatory climate conducive to an aggressive pipeline exploration program.

8. For many years the Commission has determined the cost of pipeline-owned production facilities, like the other components of a pipeline's jurisdictional operations, on an individual company cost-of-service basis. See, *e.g.*, *Canadian River Gas Co., et al.*, 3 FPC 32 (1944), affirmed *sub nom.; Colorado Interstate Gas Co. v. F.P.C.*, 142 F.2d 943 (CA10, 1944) affirmed, 324 U.S. 581 (1945); *Cities Service Gas Co.*, 3 FPC 459 (1943), affirmed, 155 F.2d 694 (CA10), certiorari denied, 329 U.S. 773 (1946); *City of Cleveland, v. Hope Natural Gas Co.*, 3 FPC 150 (1942), affirmed *sub nom.; F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Panhandle Eastern Pipe Line Co. v. F.P.C.* 324 U.S. 635 (1945). However, we have turned to an area pricing approach with respect to the just and reasonable price at which independent producers–who on a national basis provided 86.41 percent of the gas entering into the lines of the respondent interstate pipelines in 1962, and as of that year owned an estimated 82.36 percent of total reserves owned by or dedicated to the respondent pipelines–may sell gas to the interstate pipelines. The issue in Phase I of this proceeding is whether we should now apply such area rates, or some variant or modification thereof, in future pipeline rate cases to value the gas produced from pipeline ~~owned~~ (or pipeline affiliate owned) leases acquired after the date of this decision and taken into the pipeline's own system.

9. For the reasons set forth, we conclude that, subject

[11281]

to a showing in such future pipeline rate cases of special circumstances warranting a different result, the just and reasonable area rate ceiling governing sales by independent

[11282]

producers to the various pipelines (or, where area just and reasonable rates have not yet been set, the appropriate in-line or guideline price applicable to sales by independent producers) should be utilized for such purposes.

10. It is important at the outset to define the limitations of this decision. We are not primarily concerned in this proceeding with pipeline production sold off system to other pipelines. We think that the applicable area rate should apply to such production. Furthermore, we have previously held in *Union Producing Company*, 31 FPC 41, that gas sold off-system by affiliates should be treated like production from independent producers, and there is no reason to disturb this conclusion here. Nor are we concerned here with gas taken into a pipeline's system–past, present, or future–from production facilities on leases acquired prior to the date of the decision herein. The question of whether we should prospectively depart from pricing such gas on an individual company cost-of-service basis is to be considered in Phase II of this proceeding. That issue involves separate problems relating to the historical context under which such production efforts were undertaken which by no means necessarily call for the same resolution to be given to future production from leases acquired after, and in the light of, this decision.

11. The legality of the existing system of valuing pipeline production utilized in the pipeline's operations by no means attests to its rationality with respect to future acquired leases. Most, if not all, of the basic incongruities presented in attempting to fix the cost of an independent producer's production on an individual company, historical, cost-of-service basis, to which we refererd in the second *Phillips*

case, [4] and in the *Permian* area rate case, [5] are equally applicable in the case of a pipeline's own production. In fact, they were originally noted by Justice Jackson in opinions relating to the costing of a pipeline's own production, issued prior to the time when it was recognized that this Commission had any responsibility

---

[4] *Phillips Petroleum Co.*, 24 FPC 537, 542-548 (1961), affirmed *sub nom., Wisconsin v. F.P.C.*, 303 F.2d 380 (CADC, 1971), affirmed, 373 U.S. 294 (1963).

[5] *Permian Area Rate Proceeding*, Docket No. AR61-1, 34 FPC 159, 178-179, affirmed *Permian Basin Area Rates Cases*, 390 U.S. 747.

[11283]

for fixing the rates at which independent producers sold gas in interstate commerce. [6]

12. These logical anomalies in continuing to price pipeline-owned production on an individual company cost-of-service basis are clearly enhanced, once the maximum sales prices by independent producers (who are, and at least in the foreseeable future will continue to be, the primary source of natural gas) are set on an area basis. Thus, if a pipeline can purchase gas from independent producers in a given field at an area price fixed by the Commission, a most serious question is presented as to whether it would be in the public interest (and not unduly discriminatory) to permit a pipeline to charge its customers a substantially higher price for gas it produced itself from the same field merely because its overall costs of production for a particular test period turned out to be higher than the area rate. Conversely, if, as many of pipeline participants in this proceeding urge is the case, pipelines can successfully conduct production operations at the area rate fixed for independent

producers, there is no reason why their consumers should be deprived of the benefit of such enhanced participation in the production area by industry elements specially concerned with the maintenance of an adequate gas supply, merely because some of the pipelines–or even a majority of them–can conduct such operations at a more profitable rate of return than we might allow the pipeline as a whole to earn on an individual cost-of-service basis. 7/

13. Cost-of-service pricing of pipeline production, except with respect to some old production facilities acquired at very low cost before the development of the natural gas industry as we know it, has led in the main to high-cost gas coupled with a continuing reduction in the relative amount of pipeline production.

6/ See *F.P.C. v. Hope Natural Gas Co.*, 320 U.S. 591 at 649 (1944) (Dissenting opinion); *Colorado Interstate Gas Co. v. F.P.C.*, 324 U.S. 581 at 610 (1945) (Concurring opinion).

7/ We note that we lack authority to preclude pipelines from choosing to enter areas of operation considerably more risky and less related to pipeline operations than gas production, and that if we were to preclude the successful pipeline producer from reaping the rewards which may be available at area rates, the alternative is not likely to be greater production activity at lower yields.

[11284]

If pipelines, by moving to an area rate technique, can be encouraged to increase their activity in the search for and production of gas without increasing the overall cost of the gas to the consuming public, this certainly should be encouraged. And assuming, *arguendo*, the continuing applicability of the dictum of *City of Detroit v. F.P.C.*, 230 F.2d 810 (CADC 1955), certiorari denied 352 U.S. 829 (1956), clearly the "anchor" the court there felt should be the "point of departure" in moving to a pricing system other than the conventional rate-base method (*ibid.*

at 818-819) lies in the approved just and reasonable area rates for independent producers.

14. We arrive at this conclusion at a time when there are indications of a shortage of gas and a threat of a greater shortage in the future. For instance, for the first time the American Gas Association reported that in 1968 net gas production exceeded the reserves added resulting in a decline in total proved reserves from 292.9 trillion cubic feet to 287.3 trillion cubic feet by the end of 1968. 8/

15. While the 1968 figures are not in the record, the present trend is reflected by the record. Preeminent are the reserve-production ratios showing the ratio of reserves to production during the year. This ratio, for the United States, with some slight ups and downs, has trended generally downward from 22.1 in 1965 to 14.8 in 1968. Of course, the reserves owned by pipeline producers are only a portion of the whole but pipeline production has not been progressing satisfactorily. In fact, the owned reserves of pipeline producers have declined 29.9 percent between 1958 and 1966, and, as a percentage of total reserves, have declined from 25 percent in 1958 to 13 percent in 1966. In spite of this trend, as argued by the Pipeline Production Group and other parties, the pipeline producers are capable of making a significant contribution to new gas supplies.

16. It is contended that the area price concept cannot legally be made applicable to the production operations of pipelines since the record evidence of their historical costs of operation shows a considerably greater spread from the mean average than in

8/ AGA Committee on Annual Gas Reserves; Report issued April 7, 1969.

[11285]

the case of independent producers. This evidence, however, merely reflects the wide divergencies in the periods of time and surrounding circumstances in which the pipelines presently with production originally undertook such operations, and by no means indicates that their costs for production from future acquired leases are likely to diverge significantly over a period of time, either from one another or from the average experience of independent producers on similar lease vintages.[9] Similarly, the argument that the cost evidence from the all-areas questionnaire

[9] Particular pipelines, of course, could experience higher than average costs if, for example, they made a practice of purchasing more developed and hence more expensive leases. While there could be circumstances where more costly operations were required by public convenience and necessity (such as arguably was the case when El Paso, then largely dependent upon casinghead gas subject to the vagaries of oil production regulation, purchased developed acreage in the San Juan Basin), the area rate pricing technique quite appropriately places the burden for demonstrating the special circumstances for imposing the extra cost of such operations upon the pipeline. The present cost-of-service methodology, on the contrary, tends to put a premium upon high-cost operations (and upon indifference to cost considerations), in view of the extreme difficulty of the agency meeting the standard required to disallow expenditures as improvident.

NB

In this same context is the use by pipelines of their reserves as as flexible source of gas supply; in other words they are said to "swing" on their reserves. There may be good reasons why it is appropriate for a pipeline to "swing" on its reserves. Its independence in this respect and others is one of the advantages of a pipe-

line owning its reserves, and the advantage to the pipeline may offset any financial detriments incurred. On the other hand it may be more advantageous for a pipeline to purchase its gas supplies from independent producers. Under normal conditions, we can leave these matters to the judgment of the pipelines, and, if pipeline production is subject to area rates rather than individual cost-of-service, the consumer will be protected against expensive modes of operation where there is no corresponding cost saving.

[11286]

demonstrates that the pipelines as a group had per Mcf costs significantly higher than those of the independent producers, does not demonstrate the invalidity of utilizing the area rates already fixed, or to be fixed, for future vintages of gas produced by independent producers; not only is the issue here limited to future gas vintages with respect to which such historical experience is not the measure for fixing just and reasonable rates, but the techniques applied in both the *Permian* and *Southern Louisiana* area rate cases to fix the area rate ceilings for future vintages of gas depended, in large part, upon industry-wide statistics which included the current production experience of the pipelines.

17. Equally unpersuasive are the contentions made by the Commission's staff, endorsed by the California Commission, that, while an area rate should be applied to pipeline production, the price to be permitted independent producers for gas from new leases should be significantly reduced for pipelines bv substituting individual pipeline costs or allowances for various components of the area rates as determined in *Permian* and *Southern Louisiana* Primarily the staff would allow only the lower over-all rates of return fixed for the individual pipelines instead of the 12 percent rate specified for independent producers in both the *Permian* and *Southern Louisiana* cases, and would utilize the individual pipeline plant liquid credit figures. We are not per-

suaded that the financing of pipeline production operations are in fact markedly cheaper than the financing of such efforts by independent producers, or that pipelines can significantly utilize their debt resources to reduce the cost of production activities. Moreover, we think the argument of the Pipeline Production Group that the staff has chosen for special treatment the facets of production operations which might tend to be cheaper for pipelines, while using the general industry-wide figures in those areas where pipeline production costs might be expected to be above average, has considerable merit.

17. The principal objection to the staff position, however, lies in its basic assumption that if, as the staff apparently believes, average pipeline production costs for future developed leases will or should be cheaper than the costs of independent producers, the differential should accrue to the pipeline's rate-payers rather than to the pipeline. This is virtually

[11287]

guaranteed to discourage pipelines from entering the production area to any large degree. It is, moreover, basically inconsistent with a major premise of area pricing, that low-cost producers should reap the reward of their luck or efficiency. There is certainly no less reason why this should be true for pipelines than for independent producers. On the contrary, since the pipelines can be expected to have a greater incentive to explore for and develop gas reserves than the independent producers, the assurance that they will be rewarded if, despite the risks of any production operation, they can produce gas at less than average cost can only benefit the consuming public. At the same time the public is protected by the area rate concept from bearing the brunt of the unsuccessful or otherwise unnecessarily high-cost pipeline production efforts.

19. Consolidated, while supporting the area rate concept

for pipeline production generally, argues that for Appalachia pipeline production should continue to be regulated on an individual company cost-of-service basis. The atypical nature of Appalachian production as a matter of history cost, relative importance of pipeline production activities, production per well and value of the gas in view of its location factor are among the reasons advanced for separate treatment. To a large extent it would appear that these arguments (which to a varying extent are also applicable to some of the other production areas outside of the major production regions in which area rate proceedings have already been held or are in progress) are primarily directed to the question of what the particular area rate level should be, rather than whether individual company cost-of-service pricing should be maintained for pipeline production of future acquired leases.[10] Thus Consolidated's arguments make clear the inappropriateness of any individual company cost-of-service pricing for the many small independent producers in Appalachia. At the same time serious questions could be raised as to the propriety of any system which would fix an area rate for independent producers which would permit them to secure less for comparable production operations than

[10] Gas from such leases taken into a pipeline's system is most unlikely to be involved in pipeline rate cases in any significant amount, prior to the establishment of area just and reasonable prices.

the pipelines could secure on a cost-of-service basis, or the feasibility of a system under which area independent producers would be allowed to secure different rates for their gas depending upon the differing production costs of the pipelines they sold to (with still different prices where the pipeline purchasers are not themselves producers).

20. We do not, however, attempt any conclusive determi-

nation of this question here. Our general policy, in the case where pipeline production taken into its system from newly acquired leases originates in areas where there is no just and reasonable area rate, will be to allow the appropriate in-line, or guideline, price applicable to independent producers in such area,[11] but we shall provide all pipelines an opportunity in such rate cases (analogous to the petitions for special relief available to independent producers) to show that the public interest requires special treatment for their own production.

21. An issue has been raised in this proceeding as to the treatment in any pipeline rate case of any Federal income tax credits which may be available to the particular pipeline as a result of its production activities on newly-acquired leases. Of course, in the pipeline's rate case such production will be allowed an area rate in which the presence or absence of a tax component will depend upon whether it has been shown that, under the tax laws then in effect, gas production operations of the industry as a whole on the average result in the payment of any Federal income taxes. But regardless of this determination, it is to be expected that some pipelines (like some independent producers) will be able to show that they paid taxes on their production activities, while others (also like some independent producers) will have tax credits which can serve to reduce the taxes upon their other operations.

---

[11] In the case of San Juan the 13-cent per Mcf new gas rate may well be too low under governing cost and value conditions to serve as an inducement price, and we will be prepared to consider its modification. However, in the absence of a showing not approached on this record, we see no basis for establishing a differential system under which pipelines would receive a substantially greater price for production from newly-acquired leases than independent producers.

[11289]

22. The staff contends that any tax credits which accrue to an individual pipeline should be deducted from the tax allowance for its pipeline transmission operations. (Presumably, under this view, where a particular pipeline could show its production activities from newly-acquired leases incurred federal taxes, they would be added to the allowance for the pipeline's transmission operations; otherwise, the inequity of the staff proposal would be apparent.) The Pipeline Production Group, on the other hand, claims that to be put on a par with independent producers, who, to the extent market forces permit, can utilize tax savings as they see fit, the pipeline producers should be entitled to the benefit of the tax credits by not having them considered in fixing the tax allowance on their transmission operations.

23. Under circumstances where the pipeline's production activities, like the rest of its system, are valued for rate-making purposes on a conventional individual company cost-of-service basis, it has been held that tax credits from production operations must be utilized to reduce the taxes paid on the total jurisdictional operation, thereby decreasing the pipeline's overall cost of service, and should not be used as an inducement for pipelines to participate in the production of natural gas. Under individual company cost-of-service pricing of production facilities this inducement is the function of the Commission's rate of return determination, and, if a higher return is appropriate for the production side of the pipeline's activities, this must be justified as such rather than through treatment of the production tax benefits. *El Paso Natural Gas Co. v. F.P.C.*, 281 F.2d 567 (CA5, 1960), certiorari denied 366 U. S. 912.

24. We do not believe that the holding of this case is applicable to the situation presented here, where the pipeline's production activities are being valued on the area rate basis applicable to independent producers, who have the option to reinvest the advantages of any tax credits they may incur as a result of their gas production activities into further gas exploration and development. If, as we hold,

[11289]

pipelines engaged in production activities are to be treated in the future, on newly acquired leaseholds, as though they were independent producers, and afforded a per Mcf price for gas taken into their systesm totally unrelated to their particular costs, particular rate of return considerations, or particular tax

[11290]

situation, then we believe they should be placed on a par in all respects. This should include the availability to the individual pipeline as a result of its production activities of any tax credits or its incurrence of any tax liability.

25. It is possible that some pipelines, like some independent producers, will choose not to utilize any tax credits they happen to accrue from their gas production activities to advance their production activities. But this is no more a basis for establishing a pricing system which puts pipelines, as a class, at a disadvantage than would be the case if we were to hold that pipelines as a class should be on area rates with respect to their production activities, while how-cost pipelines should be required to flow through some or all of their cost savings to their ratepayers. Essentially, the staff's position on production tax credits is that pipeline production should be priced upon the basis of an area rate maximum price, discounted by savings relevant to an individual company cost-of-service approach. As we have stated earlier the end result of such a pricing system would tend to discourage the pipelines from entering into or increasing their current rate in the production field.

26. Pipeline producers are henceforth to be treated on a parity with independent producers. By so doing we are encouraging intensified exploration by the pipeline producers. We would anticipate that gas produced from leases acquired after the issuance of this opinion would be promptly dedicated in the public interest to assure the adequacy of the supply of natural gas.

Over-all order

27. In accordance with the above discussion we shall require that pipeline producers generally price the new lease gas produced by or delivered to them by their affiliated producers at the area rate applicable to gas under contracts of a vintage corresponding to the date of completion of the first well on the lease. Consistent with our decision in Opinion No. 567 *(Area Rate Proceeding*, Docket No. AR64-1, ——— FPC ———, issued October 3, 1969), the area rate applicable to production from any gas reservoirs discovered on such leases after the date of completion of the first well shall be controlled by the discovery date. However, where the pipeline or its affiliate acquired developed leases from which jurisdictional sales are being made

[11291]

the applicable price shall be the lower of the contract price or the applicable area price, so that the acquisition of gas reserves by the pipeline does not result in an increase in price. Where the pipeline or its affiliate acquires a developed lease from which nonjurisdictional sales are being made, the gas will be priced at the area price applicable at the date of lease acquisition. In any case where there is no area rate we shall require that they employ the in-line price determined by us or, failing that, the guideline price. We are also providing for exceptions from the area rate upon a proper showing of special circumstances in a pipeline rate filing.

28. Pipelines should keep their records on a basis which will enable them and the Commission to achieve the necessary division of costs. We have instructed our Staff to examine the need for amendments to our Uniform System of Accounts and rules governing pipeline rate filings.

29. A question has been raised by the Pipeline Group as to the effective date of these proceedings. As the Examiner points out, Phase I of the proceedings, as defined in our order of April 13, 1966 (35 FPC at p. 499), is to apply to gas produced from leases acquired after the determina-

tion of this issue. The Pipeline Group argues that the cut-off date should be January 1, 1961, used in *Permian* and *Southern Louisiana,* saying that the industry was informed by then as to the possibility of area rates being applied to pipeline production. We provided that Phase I apply only to after-acquired leases in order to expedite the proceedings and to avoid complications and evidentiary problems. The Phase I proceedings were conducted on this basis. To change the basis now would introduce issues that were not previously involved and should not be permitted.

30. Union has excepted to the Examiner's denial of its motion to be discharged from this proceeding on the ground that it is an independent producer and should be treated as such. It was made a party respondent by our order of May 25, 1966, 35 FPC 806. As an affiliate of United Gas Pipeline Company, selling gas to that company it is properly a respondent in these proceedings and its exception should be denied although it appears to have obtained its substantive objectives.

[11292]

31. A group entitled the "United Distribution Companies" on July 16, 1969 filed a petition for leave to intervene and to file a statement of position. Answers opposing the petition were filed by El Paso, the Municipal Group and our staff. Because the petitions are not timely, a number of members of the group are already represented in these proceedings, and the assertions made by the group of a gas shortage do not add any new element to our general knowledge of the industry or the record in these proceedings, we shall deny the petition.

The Commission further finds:

(1) The notice and effective date provisions of Section 4 of the Administrative Procedure Act, 5 U.S.C. 553, do not apply with respect to the amendment here adopted.

(2) It is appropriate and in the public interest in administering the Natural Gas Act to promulgate Commission policy on pricing natural gas produced by pipelines and their affiliates from leases acquired after the date of this order.

The *Commission*, acting pursunat to the authority of the Natural Gas Act, as amended, particularly Sections 4, 5, 8 and 16 thereof (52 Stat. 822, 823, 825, 830; 76 Stat. 72; 15 U.S.C. 717c, 717d, 717g, 717o), *orders:*

(A) Effective upon issuance of this statement, Part 2, Subchapter A, General Rules, Chapter 1 of Title 18 of the Code of Federal Regulations, is amended by adding a new Section 2.66 to read as follows:

§2.66 *Pricing of New Gas Produced by Pipelines and Pipeline Affiliates.*

(a) As a matter of policy in future pipeline rate proceedings, gas produced by pipelines or by their affiliates from leases acquired after the date of this order will be priced for rate making purposes at the just and reasonable area rate applicable to gas of a vintage corresponding to the date of completion of the first well on the lease, otherwise at the "in-line" price, or, if there is no in-line price, on the basis of the guideline price set forth in Section 2.56 of our Rules, with the following exceptions.

[11293]

(1) If a pipeline or pipeline affiliate acquires a developed lease from which jurisdictional sales are being made, the applicable price of gas shall be the lower of (a) the contract price applicable to the gas, or (b) the applicable area price (or in-line or guideline price);

(2) If a pipeline or pipeline affiliate acquires a developed lease from which nonjurisdictional

[11293]

sales are being made, gas produced from the lease will be priced at the just and reasonable area price applicable to gas of the vintage corresponding to the date of lease acquisition, (or in-line or guideline price);

(3) If the pipeline is able to show in a rate proceeding that special circumstances exist which justify different treatment, such a showing should be made by means of a special schedule and supporting evidence filed in addition to the material otherwise required by Section 154.63 of the Regulations.

(b) Pipelines acquiring production leases subsequent to the date of this opinion either on their own part or through affiliates should:

(1) Where they have their own production maintain separate subdivisions of their plant and expense accounts related to production properties and production activities, so as to show separately costs related to production from present leases and costs related to production from leases acquired after the date of this opinion;

(2) In making a rate filing provide additional detail in subdivisions within the production function, i. e., as between gas from present leases and gas from leases acquired after the date of this opinion with respect to their own production and also with respect to any production of their affiliates.

[11294]

(B) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion, to be made in the Federal Register.

(C) Union Producing's request to be discharged from these proceedings is denied.

(D) The petition filed July 16, 1969, by the United Distribution Companies for leave to intervene and file statement of position is denied.

(E) Except as herein granted, the exceptions to the initial decision are denied.

By the Commission.
(SEAL)

Gordon M. Grant,
Secretary.

[11307]

UNITED STATES OF AMERICA
BEFORE THE FEDERAL POWER COMMISSION

In the Matter of:	)	
	)	Docket No. RP66-24 (Phase I)
Pipeline Production Area Rate	)	
Processing	)	

PETITION BY
MUNICIPAL GAS GROUP FOR REHEARING

Pursuant to Rule 1.34 of the Commission's Rules of Practice and Procedure, the Municipal Gas Group[1] requests the Commission to reconsider its decision (Opinion No. 568) issued on October 7, 1969, on the basis that the findings and conclusions of the Commission rejecting cost of service and substituting area rate treatment for new gas produced by the nation's interstate pipelines and their affiliates are unsupported by this record, contrary to the principles of the Natural Gas Act, lacking in legal support, contrary to

[11307]

established Commission policy, and inimical to the best interests of the gas consumers of the nation. Specifically, objection is noted to and reconsideration is urged of the findings and conclusions.

1. The Commission improperly now seeks to treat the proceedings in this case as in the nature of a rule-making proceeding rather than an adjudication controlled by the record hearing provisions of the Administrative Procedure Act (5 U.S.C. § 554 (1967 Supp.)). From its inception as part of the *Hugoton-Anadarko Area Rate Proceeding*, FPC

---

[1] Consisting of the American Public Gas Association, the City of Chicago, the City and County of Denver, and the Memphis Light, Gas and Water Division.

[11308]

Docket No. AR64-1, and thereafter as severed by the Commission's Order of April 13, 1966, Docket No. RP66-24, this proceeding has been established as an "Area Rate Proceeding", treated as an adjudication on the record in a similiar manner to the other Area Rate cases, namely, *Permian*, AR61-1; *Southern Louisiana*, AR/62-2; *Hugoton-Anadarko*, AR/64-1; *Texas Gulf Coast*, AR64-2; and *Other Southwest Area*, AR67-1. In each of these cases a hearing in the nature of an adjudication based on the record was required to fix proper rates. The Commission prior to Opinion No. 568, properly denied requests to convert the present proceedings into a rule-making proceeding. However, in its Opinion No. 568, the Commission improperly seeks to circumvent the record in this case, a record which impelled the Presiding Examiner to find that the proponents of area rates for pipeline production had failed to justify a change from the established cost-of-service method of regulation. The Commission's action, by fixing rates without

limitation to the hearing on the record, deprives the consumers of due process of law in violation of the Fifth Amendment of the Constitution and the hearing provisions of the Administrative Procedure Act. [Par. 1, 2.]

2. The Commission's finding of "an apparent gas shortage" is not supported by the record in this proceeding; rather it is based upon industry-oriented statistics, the American Gas Association Committee Report of April 17, 1969, concededly not in the record. The report was issued more than two months prior to the oral argument in this proceeding, June 27, 1969, but no action was taken to introduce these industry statistics into the record subject to cross examination. The A.G.A. figures are internally inconsistent and reflect unexplained manipulations of data. Neither the Commission nor any party to this case has ever had the opportunity to review the data used in the A.G.A. figures. In fact, there has been no valid proof of any sort of the asserted "gas shortage"

[11309]

upon which the Commission relies. In the absence of proof and opportunity for cross examination and rebuttal, the blind acceptance by the Commission of the extra-record, self-serving industry statements deprives the consumers of the protection accorded them by the terms of the Natural Gas Act. [Par. 7, 14, 31.]

3. The Commission erroneously seeks to abandon the thirty years of judicially established precedents for the individual cost-of-service method of regulation for on-system gas produced by pipeline companies. These precedents have distinguished production of gas by pipelines from production of gas by independent producers. The different regulatory approaches are necessary to protect consumers against unjustified profits. The most recent example is the decision of the Tenth Circuit Court of Appeals in *Cities Service Gas Co. v. F.P.C.* (10th Cir., No. 151-68, October 16, 1969), where the court upheld cost-of-service treatment

[11309]

for gas pruchased by a regulated pipeline from a nonaffiliated company which had previously purchased a producing affiliate of the pipeline. That case reveals the substantial impact on consumers in higher gas costs of a shift from cost-of-service to area rates, and the court noted the long-standing distinction between pipeline production and area rate production. The Commission decision on Opinion No. 568 is inconsistent with the *Cities Service* case and would permit the result there barred for all future acquired lease production. [Par. 7, 8.]

4. The Commission's conclusion that the rate treatment considered just and reasonable for independent producers is *ipso facto* just and reasonable for pipeline producers is contrary to the weight of the evidence of record in this proceeding.

5. The Commission erroneously concludes, in complete disregard of the basic differences between the independent producer and the piepline producer as demonstrated on this record, that the "basic incongruities" (which

[11310]

it does not specify) which led to the decision not to use individual cost-of-service in independent producer price regulation are "equally applicable in the case of a pipeline's own production." The precedents establishing individual cost-of- service for pipelines and area rates for independent producers have clearly differentiated the need for different regulatory treatment to protect consumers from paying unjustified profits to pipelines. [Par. 11.]

6. The Commission erroneously concludes in complete disregard of the utility function of the pipeline that pipelines have no business being in the producing business unless they can produce gas at, or less than, the area rate, based on the implicit findings: (1) that a pipeline's policy of producing a protion of the supply for its pipeline cannot be related to the objective of utilizing its reserves on

an optional, economic basis (swing); (2) that a pipeline can prudently eliminate the production function, or refuse to go into it under any and all circumstances; and (3) that pipeline production cost-of-service hypothesized as exceeding an area rate for alternative gas theoretically available must be allowed in fixing rates. This last implicit finding assumes *inter alia* the absence of the Commission's ability or inclination to exercise its authority to disallow excessive or imprudent costs or to otherwise impose regulatory restraint against excessive pricing. Stripped of its facade of presumed protection to the consumer, the Commission's new regulatory treatment is designed to allow pipelines more than the just and reasonable return on production operations available under individual cost-of-service, not less. [Par. 12, and note 9 of par. 16.]

7. The Commission improperly concludes that a mere increase in the price available for gas, which is all that resort to area rates for pipeline produced gas does, will result in increased exploration and development. No evidence in the record sustains this. To the contrary, the record shows that pipeline producers have achieved a higher reserve

production ratio under individual cost-of-service regulation than have the independent producers under area rates. [Par. 13, 18, 26.]

It is significant to note that with respect to the arguments advanced by the Pipeline Production Group for area rates and the decision of the Commission accepting these arguments, this proceeding has become merely a replay of the *Panhandle Eastern Pipe Line Company* case (13 F.P.C. 53 (1954), which was reversed in *City of Detroit v. F.P.C.* 230 F.2d 810 (D.C. Cir., 1955), *cert. denied*, 352 U.S. 829 (1956). The pipeline interests in the *Panhandle* case also, in an attempt to obtain a higher price for pipeline produced gas, employed the now familiar tactics of claiming a marked decline in the reserve production ratio as evidence of a need

for a change. *Id.* at 74-76. On remand after *City of Detroit*, the Commission recognized that the evidence submitted by Panhandle did not justify abandonment of the protection afforded consumers under individual cost-of-service. *Panhandle Eastern Pipe Line Co.*, 25 F.P.C. 787 (1961). The Court of Appeals for the District of Columbia Circuit affirmed, 305 F.2d 763, *cert. denied*, 372 U.S. 916 (1963) after noting the second *Phillips* case. Unpredictable windfall profits to individual pipelines under area rates have not been justified on the record by the Commission as providing only the amount necessary but no more than is necessary to elicit additional productivity. On the contrary, under cost-of-service the Commission, by direct control over amounts allowed in the cost-of-service for exploration and development can directly provide for such activities without allowing exorbitant profits to pipelines. [Par. 13.]

8. The conclusion of the Commission that substantially all gas produced by pipelines under cost-of-service pricing is "high-cost gas" and the further implication that this pricing system was responsible for a "continuing reduction in the relative amount of pipeline production" is completely contrary to the evidence in this record. *See, e.g.*, Tr. 4358-60; Sch. H, Sheets 1 and 3; Sch. 6, 7, 12, Ex. No. 58; Appendix B, Ex. No. 58 [Par. 13.]

11312

9. Exception is taken to the Commission's implication that adoption of area rates for pipeline production will not increase "the overall cost of the gas to the consuming public." To the contrary, (1) the entire purpose of urging application of area rates to pipeline production is to increase the cost of gas to the consumer thereby allegedly encouraging additional production by the low-cost pipelines; and (2) the application of area rates to pipeline production removes the incentive for pipelines to bargain to keep area rates at the lowest possible level to obtain lower cost gas supplies for the benefit of the consumer. *See, Permian Basin Area Rate Cases*, 390 U.S. 747, 793-94 (1968). [Par. 13, 18.]

10. The Commission's arbitrary conclusion that the *City of Detroit* (230 F.2d 810, 818-19 (D.C. Cir., 1955)) criteria for departure from conventional cost-of-service pricing is met because area rates have been adjudicated just and reasonable with respect to independent producers is completely contrary to law. This conclusion reflects a total misunderstanding of the legal principles involved in *City of Detroit.* Merely because the area rate system is deemed just and reasonable for independent producers does not necessarily make it just and reasonable for pipeline producers. In so construing the case, the Commission has avoided its responsibility to use cost-of-service as a departure point for a comparison with area rate procing for pipeline production and to demonstrate that a need for a change exists and that the area rate system will meet that need better than the cost-of-service system and at the same time provide just and reasonable rates for the consuming public. (*Id.* at 817-18.) *City of Detroit* clearly specifies that in determining whether *and* alternative method fulfills the criteria indicative of a just and reasonable rate, the presumed impact of the alternative on the pipeline and on the consumer must be measured against the performance of the current method of regulation. (*Id.* at 813, 816-18.) The Commission has not shown and cannot show on the present record that comparison necessary to justify abandonment of cost-of-service. [Par. 13.]

[11313]

11. The finding that the "owned reserves of pipeline producers have declined 29.9 per cent between 1958 and 1966" is in conflict with this record, specifically with Exhibit Nos. 6 and 21. [Par. 15.]

12. The finding that the "owned reserves of pipeline producers. . . as a percentage of total reserves, have declined from 25 percent in 1958 to 13 percent in 1966" is in conflict with this record, specifically with the testimony of Staff Witness Zabel at page 567 of the Transcript of Rec-

ord which showed that "owned reserves of all of the Group I producing pipelines represented only 7.5 percent of the total AGA-API gas reserves for the total continental United States in 1965." [Par. 15.]

13. The finding that "pipeline production has not been progressing satisfactorily" is objectionable on two bases: (1) the statement is ambiguous and meaningless in that it does not indicate the standards or criteria by which the alleged unsatisfactory progress is measured; and (2) it is in conflict with the record on the reserve production ratio question made in this proceeding. *See, e.g.*, Ex. No. 21, Sch. 1, col. II and Sch. 7, col. 7 (1940-1957); Ex. No. 6, p. 8 (1958-1965). [Par. 15.]

14. The record does not support the conclusion that average future costs for independent producers and pipeline and affiliated producers will tend to coincide, thus establishing sufficient cost comparability to justify application of area rates to pipeline produced gas. *See, e.g.*, Ex. No. 58, Sch. 21, pp. 1, 3, 4, Sch. 35, 36 and 37. [Par. 16.]

15. The Commission is in error in abandoning the accepted court-approved index of the pipeline gas producer's profit included in cost-of-service which is equated with his incentive to produce gas, that is, return on equity investment. [Par. 17.]

[11314]

16. The record does not support the conclusion of the Commission in allowing the pipelines an exorbitant 20 to 40 percent return of equity on production operation. The Commission erroneously concludes "that the financing of pipeline production operations are in fact [not] markedly cheaper than the financing of such efforts by independent producers, or that pipelines can [not] significantly utilize their debt resources to reduce the cost of production activities." The Commission refuses to acknowledge the economic realities of the position of the independent producer vis-

a-vis the pipeline producer,[2] namely that because of the difference in capital structure between the pipeline producer and the independent producer, the return on equity at the same overall rate of return is much higher for pipelines. This results in the anomaly that although the Commission in this opinion proclaims "parity" of the independents and the pipeline producers, it in fact is placing the pipeline producer in a position of "super-parity" in that the 12 percent overall return accorded the pipeline will result in an excessive return on equity to the pipelines ranging between 20-40 percent, to the detriment of consumers. [Par. 17, 25.]

17. There is no proof that pipelines will engage in any extra production if given extra profits beyond the present return on equity determined by the Commission under prior precedents for each individual pipeline as adequate to attract capital for all their operations, inclusive of production operations. Conversely, the Commission errs in assuming

2 This difference and the resulting necessity for differing rate of return treatment to the independent producer in contrast to the pipeline producer was acknowledged in the following illustrative cases: Permian Basin Area Rate Cases, 390 U.S. 747, 806-808 (1968); Panhandle Eastern Pipe Line Co. v. FPC, 305 F.2d 763, 766-67 (D.C. Cir., 1962); Southern Louisiana Area Rate Proceeding, ¶10, 983 CCH Utilities Law Reporter, Federal New Matters 13, 616-617; and in Phillips Petroleum Co., 24 F.P.C. 537, 575-76 (1960).

that retention of such excess profits by pipelines under the area rate treatment afforded in Opinion No. 568 will in any benefit consumers forced to pay higher rates therefor. There is no more reason for consumers to pay an extra increment of profit to a regulated pipeline to engage in production activities than for it to engage in any other activity in support of its overall utility operation. [Par. 18.]

[11315]

18. The conclusion of the Commission that cost-of-service pricing will be permitted if the pipeline is able "to show that the public interest requires special treatment for their own production" has the de facto effect of permitting cost-of-service or area rates, whichever is higher. With respect to the position of the consumers vis-a-vis gas prices, this result can be translated into a game of "heads I win, tails you lose." The failure conversely to allow consumers to urge cost-of-service re lower than area rates under "special circumstances" demonstrates the one sided, discriminatory nature of the Commission's attempt to protect the industry, not the consumers. [Par. 18-20.]

If the Commission does not intend this result to follow from its opinion, it must clarify the deficient and very general, "special circumstances" language, defining and limiting it in some manner so that the pipeline is not so obviously assured that it is entitled to select either the area price or the cost-of-service, whichever is higher. The definition of standards should not be left for future litigation.

19. The Commission's conclusion that the application of area rates to pipeline production must deprive the consumer of paying only the actual taxes incurred by the pipeline, thus preventing the tax credits from production from reducing the taxes allowed in cost-of-service of the transmission operation, is completely contrary to the holding in *El Paso Natural Gas Co. v. F.P.C.*, 281 F.2d 567 (5th Cir., 1960), cert. denied, 366 U.S. 912, and a long line of cases affirming the actual taxes paid concept. The Commission although according lip service to consumer protection principles, in fact

[11316]

chooses to disregard the principles adopted by the courts to assure consumer protection from exploitation by the pipeline companies. The Commission concludes that since the Commission has decided to value pipeline produced gas at the area rate applicable to independent producers, the stric-

tures of the *El Paso* case re the flowing through of tax benefits are henceforth inapplicable. The holding in *El Paso,* although necessarily rendered in a cost-of-service proceeding, was not restricted to application in such a case; rather, it was a principle of general application looking to the protection of the consumer interest. The court held (*Id.* at 571-573) that the tax benefits were not to be translated into "additional profits for the regulated company over and above a reasonable return on its investment." Further, the court found that "such savings as are effected are passed on to the consuming public" as a natural and necessary consequence of rate regulation.

It is evident that the court did not speak of rate regulation only in the cost-of-service term; rather, its application of the principle is a general one. The effect of Opinion 568 means that the transmission cost-of-service would include imputed or hypothetical expenses for taxes not in fact paid. The result would be an allowance of a return clearly in excess of the fair rate of return from transmission operations. Not only would the Commission deprive the consumer of the flow-through tax benefit, but also because it imposes no requirement on the pipelines to plow back their tax credits into their production operations, it is quite possible that these credits would be utilized in a venture bearing no relation to the need for additional gas reserves. [Par. 21-25.]

20. The conclusion of the Commission that permitting the pipeline to retain tax benefits results in "parity" is erroneous; it again results in "superparity". Costs of tax incurrence on transmission operations will be over-

[11317]

stated in costs allowed for rate-making purposes, with the consequence of excess returns, in effect, allowed to the pipeline producer. The independent producers have no comparable direct benefit from the so-called "parity". [Par. 21-25.]

[11317]

21. The Commission's conclusion that its opinion results in "parity" treatment of independent producers and pipeline producers is incorrect. In fact, the pipelines are placed in a "super-parity" position particularly with respect to the following items (1) application of the same numerical overall rate of return to pipelines as to independents will result in at least a doubling of "profit" or return on equity to the pipeline; (2) the pipeline has a built-in incentive to explore for gas because of its relationship to the earning power of a substantial transmission investment; (3) the pipeline is permitted to retain tax benefits formerly flowed through to the consumer and thereby has the opportunity to obtain excess profits from FPC regulated activities which the independent producer does not possess. [Par. 26.]

22. Objection is noted to the Commission's failure to require dedication of new gas supplies in the public interest. The Commission hopes by the Opinion not only to generate increased exploration and development activity but also to insure that the consumer interests will reap the benefits of an increased gas supply. The Commission, however, merely "anticipates" prompt dedication to the interstate consumer of new gas reserves; it makes no attempt to insure such dedication, and thereby to prevent alienation of new gas reserves from the interstate consumer the Opinion purports to benefit. [Par. 26.]

23. The Commission speculatively concludes that "parity" treatment will encourage and result in the accomplishment of "intensified exploration by the pipeline producers." There is no evidentiary basis for such a conclusion as to all of the pipeline producers. The only

[11318]

certainty is (1) that of those who chose to produce, the low-cost producers will receive a higher price for their production; (2) that area rate pricing will tend to discourage some existing producers or potential producers who may not be in the position to assume the risk inherent in exploration ac-

tivities or in possible failure to obtain an exception from the Commission as to area rate applicability; and (3) that forcing a segment of the pipelines to remove themselves from production reduces proportionately the impact the presence of such producers could have in increasing the reserve gas supply.

On the contrary, the only method or procedure presented to the Commission in this proceeding which would insure, when necessary, the production of gas where needed, by the pipelines was advocated by the Muncipal Gas Group and utilizes the existing cost-of-service approach. The Commission has the authority and the machinery, without departing from the present cost-of-service method, to make a generous individualized allowance for seeking out and developing "new" gas reserves. This allowance would be tailored to the particular history and needs of the specific pipeline. The allowance would be given special account treatment and would provide that it is subject to the condition that its use be restricted to the intended purposes. Expenditure would be required to be noted on the companies' books which would permit the Commission to guard against its dissipation, to scrutinize it with respect to its adequacy, and to determine if, in general, it achieves the intended result. Further, any portion of the allowance which is not expended would be treated as a capital contribution of the consumer. In this manner, the Commission, without departing from the cost-of-service method and without the adverse effects resulting from the Commission's announced policy, would insure that the seeking out and development of gas resources would in fact be accomplished and could insure further that the resources would be developed where and when needed. The Commission was in error in not following this course. [Par. 26.]

[11319]

24. The susceptibility of the term "new lease gas" to several interpretations renders it objectionable. As it stands, the term could be construed to include the trading or buying and selling of "old" leases among pipelines or others to make them "new". This term should be clarified to insure the application of area rates only to gas produced from new "leases acquired *and developed* subsequent to this opinion." [Par. 27.]

25. To the extent that this Opinion adopts the policy of Opinion No. 567 re the rate applicable to production from any gas reserves discovered on new gas leases after the date of the completion of the first well, namely, the date of discovery, it is objectionable and prejudicial to the consumer insofar as it places a premium on delays in the discovery of new gas reserves, since such delay might result in higher prices. The finding is further objectionable in that it could result in the pipelines favoring increases in the prices they pay for gas purchased from independent producers. This conclusion appears also to run counter to the Commission's premise that application of area rates to pipelines will bring forth more gas promptly. [Par. 27.]

26. The Commission's instruction to the Staff in Paragraph 28, supplemented in Amended Rule 2.66 to ascertain the need for and to propose amendments to the Uniform System of Accounts and rules with respect to pipeline rate filings to "achieve the necessary division of costs" is deficient in at least the following particulars and should be clarified: (1) It is devoid of standards. It fails to afford a basis, point of division, on which the Staff can proceed satisfactorily to carry out its instruction. It fails, for example, to provide the point of application of the area rate value, the adjustments and specific treatment of tax loss spillovers from production and exploration activities. This instruction should be supplemented to make it mandatory that all costs attributable to "new" gas under the prior

[11320]

individual cost-of-service method of regulation, including a reasonable proportion of past exploratory and geological costs, shall be attributed to the "new" gas cost with appropriate credits for the benefit of consumers. (2) It is vague or indefinite as to applicability to affiliate producers which are not subject to accounting rules or systems prescribed for pipelines. (3) The term "production properties and production activities," as well as the term "production" would exclude "exploration and development" under a narrow construction of the former. (4) The instruction is vague as to its applicability to general plant accounts and administrative and general expenses not covered in functional groups of accounts related to production activities. And (5) it fails to deal with the matter of quality standards and adjustments to the base area rates. [Par. 28, Order par. A.]

[11321]

WHEREFORE, for the above reasons, the Municipal Gas Group requests the Commission to reconsider its Opinion No. 568.

Respectfully submitted,

Raymond Simon
Corporation Counsel
Mathias M. Mattern
Assistant Corporation
Counsel for Public Utilities
Bernard Rane
121 North LaSalle Street
Chicago, Illinois 60602

Max P. Zall
City Attorney
City and County of Denver
City and County Building
Denver, Colorado 80202

[11321]

Of Counsel:
Reuben Goldberg
1250 Conn. Ave., N.W.
Washington, D.C. 20036

Charles F. Wheatley, Jr.
Grace Powers Monaco
2600 Virginia Ave., N.W.
Washington, D.C. 20037

Attorneys for Municipal Gas Group

November 6, 1969

[11357]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 568-A

Pipeline Production	)	Docket No. RP66-24
Area Rate Proceeding	)	
(Phase I)	)	

OPINION AND ORDER DENYING REHEARING

Issued: December 5, 1969

[11358]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

POLICY STATEMENT; AREA RATES; PIPELINES (Production);
RATES (Pipeline)

Before Commissioners: John N. Nassikas, Chairman; Lawrence J. O'Connor, Jr., Carl E. Bagge, John A. Carver, Jr., and Albert B. Brooke, Jr.

Pipeline Production	)	
Area Rate Proceeding	)	Docket No. RP66-24
(Phase I)	)	

OPINION NO. 568-A

OPINION AND ORDER DENYING REHEARING

(Issued December 5, 1969)

O'CONNOR, Commissioner:

1. Applications for rehearing in the above-entitled proceeding were filed on November 6, 1969, by the Municipal Gas Group,[1] by the People of the State of California and the Public Utilities Commission of California, and by the El Paso Natural Gas Company. In Opinion No. 568 and Order, issued October 7, 1969, the Commission provided by rule that in future pipeline rate proceedings gas produced by pipelines or by their affiliates from leases acquired after the date of the order would be priced for ratemaking purposes at the area rate, in-line price or guideline price applicable with certain exceptions as to the acquisition of developed leases and to the showing of special circumstances. Pipelines were also required to use separate accounting and to show additional detail in rate filings with respect to their present leases and leases acquired after the date of the Opinion.

2. On many of the points made by the applicants on rehearing we think that further discussion, in addition to that found in the original Opinion, would be redundant, but in other respects, further discussion or modification of our original determination is in order.

[1] Consisting of the American Public Gas Association, the City of Chicago, the City and County of Denver, and the Memphis Light, Gas and Water Division.

[11359]

3. The Municipal Group initially argues that the Commission improperly now seeks to treat the proceedings in this case as in the nature of rulemaking rather than an adjudication con-

trolled by the record hearing provisions of the Administrative Procedure Act, citing 5 U.S.C. § 554 relating to adjudications. However this proceeding may be termed, this was not our intention. We rejected a petition that informal rulemaking procedures by utilized for resolving the Phase I issues (36 FPC 954, 955). We intended to reach our conclusions upon the basis of the record and of such matters as we could take notice as an expert body. In any case, no question can be raised that all parties have not had full notice of the nature of these proceedings and full opportunity to present evidence. The issues were set forth in our order enlarging the issues in the *Hugoton-Anadarko Area Proceeding* (31 FPC 1595, June 29, 1964) and were more fully defined in our order severing these issues (35 FPC 497, April 13, 1966).

4. In connection with our consideration of the record the Municipal Group objects to our finding that the owned reserves of pipeline producers have declined 29.9 percent between 1958 and 1966, and, as a percentage of total reserves, have declined from 25 percent[2] in 1958 to 13 percent in 1966. While the statement was founded on evidence presented by the Pipeline Production Group, it is subject to criticism that it is affected by a substantial write-down of El Paso's reserves (including those of the Pacific Northwest Pipeline Company), the exclusion of the lease-sale reserves at Ship Shoals, Bastian Bay and Rayne Field and the transfer of pipeline reserves to their affiliates. Nevertheless the staff's evidence shows that reserves owned by pipelines and their affiliates attached to their systems have not kept pace in recent years with total reserves in the forty-eight contiguous states, and we think this is very significant from the standpoint of our conclusion here.[3]

[2]This was later corrected by the witness to 22 percent. The comparison made was between total pipeline reserves and the pipeline owned reserves.

[3]The staff evidence which tabulates substantially all of the on-system reserves of respondent pipelines and their affiliates amounted in millions of cubic feet to 26,004,457 in 1958, 28,396,480 in 1960 and 25,557,385 in 1965. These figures amount to 10.3 percent, 10.8 percent and 8.98 percent of gas reserves in the forty-eight contiguous states as computed by the Amiercan Gas Association Committee on Natural Gas Reserves presented in the record by the Pipeline Production Group, and adjusted to exclude Alaskan reserves.

[11360]

5. The Municipal Group argues further that the use of area rates with an exception where the pipeline is able "to show in a rate proceeding that special circumstances exist which would justify different treatment" amounts to permitting cost-of-service or area rates, whichever is higher. That was not our intention. Similar to *Permian*[4] we need not and cannot here specify all of the special circumstances which may serve as a basis for exceptions to the area rate, but the right to make a showing in no way implies that an exception will be granted merely because the pipeline cannot recover its expenses and earn the return specified for the production rate base.

6. The Municipal Group argues that there is no proof that pipelines will engage in any extra production if given additional profits beyond the present return on equity determined by the Commission. While we cannot find with certainty that area rate costing of pipeline production will cause greater production, we expect that such a pre-determined cost allowance for pipeline producers will induce exploration and development because of the assurance to pipelines that they will stand to gain as a result of superior judgment and efficiency and that any additional gains would not automatically be withdrawn to satisfy a cost formula. Moreover, since the order only applies to production from future acquired leases, "additional" returns, if any, would be earned only to the extent that pipelines were in fact stimulated to explore for and develop new reserves.

[11360]

7. Finally, the Municipal Group argues that our use of the term "new lease gas" (Par. 27) is ambiguous and that the term should be clarified to ensure the application of area rates only to gas produced from new leases acquired and developed subsequent to our Opinion. The Municipal Group is concerned that old leases could be traded among the pipelines to make them new and therefore eligible for area rates.

8. In our opinion the suggested clarification is not apt. Pipelines intending to develop leases might still be able to trade them before development in order artificially to procure benefits from area pricing. In other cases the requirement of development after the date of our Opinion might prevent

---

[4] *Area Rate Proceeding,* 34 FPC 158, 226 (1965).

[11361]

the use of area rates without justification. However, we did not intend Opinion 568 to apply to leases acquired, either directly or through intermediaries, from other pipelines or their affiliates which had held them prior to the date of our opinion. The ratemaking treatment for such leases is to be considered in the remaining phase of this proceeding. However, for the present, we will provide that such leases acquired after the date of Opinion 568 shall be subject to conventional cost-of-service treatment for ratemaking purposes.

9. While El Paso has made extensive arguments in its application for rehearing, these are largely repetitious of previous arguments and have been covered by the discussion in our original Opinion. El Paso argues, however, that our Opinion does not hold that the Examiner's numerous findings on the wide variations in pipeline production costs are incorrect, nor do we make contrary or contradictory findings which

would support our conclusion that pipeline producers' costs for production from future acquired leases are likely to be similar to costs of independent producers.

10. The Examiner's initial decision contains many findings of fact that are properly founded on the record. We differ with him, however, as to the conclusions that should be drawn. Since our approach is patently different as shown in our original Opinion, there is no reason to make determinations as to his specific findings, but we shall adopt his decision to the extent it is not inconsistent with our opinions.

11. As to our conclusion on divergent costs of pipeline producers we found (Par. 16) that the evidence "by no means indicates that their costs for production from future acquired leases are likely to diverge significantly over a period of time." We know of no reason, on the basis of a knowledge of the industry, why pipelines should not be able, regardless of their past methods and policies, to produce gas at as low a cost as the independent producers. For example, evidence presented by the Pipeline Production Group indicates that in the past pipeline producers, affiliated producers and independent producers have been equally successful within narrow limits in exploratory and developmental drilling, and pipeline drilling costs for productive gas wells have been lower than

[11362]

for the other categories. The staff shows the exploration and development expense and cash production expense ratios have been similar for producing pipelines and for other producers.[5]

The Commissioner further finds:

(1) The assignments of error and grounds for rehearing set forth in the above applications for rehearing present no facts or legal principles which would warrant any change in or modification of Opinion No. 568 and order of Octo-

[11362]

ber 7, 1969, except as specified below.

(2) The notice and effective date provisions of Section 4 of the Administrative Procedure Act, 5 U.S.C. 553, do not apply with respect to the amendment here adopted.

The *Commission*, acting pursuant to the authority of the Natural Gas Act, as amended, particularly Sections 4, 5, 8 and 16 thereof (52 Stat. 822, 823, 825, 830; 76 Stat. 72; 15 U.S.C. 717c, 717d, 717g, 717o), *orders:*

(A) The application for rehearing filed by the Municipal Group, California and El Paso are denied.

(B) Effective upon issuance of this statement Section 2.66(a), promulgated by our order of October 7, 1969, Part 2, subchapter A, General Rules, Chapter 1 of Title 18 of the Code of Federal Regulations is amended as follows:

---

[5]Exhibit 5, Sch. 4, sh. 1 and 2; Sch. 6, col. d. The production operating expense has been higher but this is accounted for by higher depletion, depreciation and amortization expense due to the high cost leases acquired by some companies. This does not indicate inherent operating differences.

[11363]

§ 2.66 *Pricing of New Gas Produced by Pipelines and Pipeline Affiliates*

(a) * * * *

(1) If a pipeline or pipeline affiliate acquires a developed lease from which jurisdictional sales are being made and Paragraph (3) below does not apply, the applicable price of gas shall be the lower of (a) the contract price applicable to the gas, or (b) the applicable area price (or in-line or guideline price);

(2) If a pipeline or pipeline affiliate acquires a developed lease from which nonjurisdictional sales are being made and Paragraph (3) below does not apply, gas produced from the lease will be priced at the just and reasonable area price

applicable to gas of the vintage corresponding to the date of lease acquisition, (or in-line or guideline price);

(3) If a pipeline or pipeline affiliate acquires a developed or undeveloped lease, either directly or through intermediaries, from another pipeline or affiliate which owned the lease prior to the date of Opinion No. 568, the lease so acquired after the date of Opinion No. 568 shall be subject to cost-of-service treatment for ratemaking purposes, subject to further determinations in Phase II of these proceedings.

(4) If the pipeline is able to show in a rate proceeding that special circumstances exist which justify different treatment, such a showing should be made by means of a special schedule and supporting evidence filed in addition to the material otherwise required by Section 154.63 of the Regulations.

* * * * * *

(Sections 4, 5, 8 and 16; 52 Stat. 822, 823, 825, 830; 76 Stat. 72; 15 U.S.C. 717c, 717d, 717g, 717o)

(C) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion, to be made in the Federal Register.

[11364]

(D) The Examiner's opinion to the extent not inconsistent herewith is adopted as a part of our Opinions Nos. 568 and 568-A in this proceeding.

By the Commission.

Gordon M. Grant,
Secretary.

UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA CIRCUIT

City of Chicago, Illinois, City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee, and the American Public Gas Association Petitioners,	)	
v.	)	No. 23740
Federal Power Commission, Respondent	)	

BRIEF FOR PETITIONERS

Richard L. Curry
Corporation Counsel
Mathias M. Mattern
Assistant Corporation Counsel
for Public Utilities
Bernard Rane
121 North LaSalle Street
Chicago, Illinois 60602

Max P. Zall
City Attorney
City and County of Denver
City and County Building
Denver, Colorado 80202

Charles F. Wheatley, Jr.
William T. Miller
Grace Powers Monaco
2600 Virginia Avenue, N. W.
Washington, D. C. 20037

Attorneys for Petitioners

Of Counsel:
George E. Morrow
Union Planters National
Bank Building
Memphis, Tenn. 38103

Reuben Goldberg
1250 Conn. Ave., N.W.
Washington, D.C. 20036

April 6, 1970

TABLE OF CONTENTS

TABLE OF CITATIONS

STATUTES

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

City of Chicago, Illinois, City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee and the American Public Gas Association, Petitioners,	No. 23740
v.	
Federal Power Commission, Respondent.	

BRIEF FOR PETITIONERS

STATEMENT OF ISSUES PRESENTED FOR REVIEW

1. Whether on the record before the Court the Federal Power Commission erred in abandoning the judicially approved individual cost-of-service method of regulating rates of gas produced by interstate pipeline companies and their affiliates established for over thirty years since enactment of the Natural Gas Act in 1938 in favor of applying the area rate method of

regulation expressly designed for independent producers, to such production.

2. Whether the Commission erred in refusing to apply the existing legal precedents governing fair rate of return for pipelines in applying area rates to pipeline production thereby allowing a 20 to 40 percent return on equity to such companies.

3. Whether the Commission erred in refusing to apply the existing legal precedents requiring that the consumers of interstate pipelines shall pay only the actual taxes incurred by the companies in disallowing any spillover of tax benefits from pipeline production operations.

4. Whether the Commission erred in relying on extra-record, untested industry-oriented statistics relating to an alleged gas shortage in support of its abandonment of the cost-of-service method of regulation and thus deprived the consumer interests represented in these proceedings of due process.

This is the first time the pending case has been before this court for review.

REFERENCES TO RULINGS

The present petition seeks review of the Opinion and Order of the Federal Power Commission No. 568 [1/] issued October 7, 1969, in the Pipeline Production Area Rate Proceeding (PhaseI) (FPC Docket No. RP66-24) and Memorandum Opinion No. 568-A [2/] denying rehearing thereof, issued December 5, 1969. In this proceeding, the Commission, reversing its Presiding Examiner, decided to abandon thirty years of established regulatory and judicial precedent requiring that gas produced and used by the nation's interstate pipeline companies be regulated on an individual cost-of-service basis under the Natural Gas Act of 1938. The Commission determined that pipelines and their affiliates can price new gas produced by them to their consumers on an area rate basis without regard to their actual costs of production, their established just and reasonable rate of return, or to their actual taxes paid on operations. The petitioners, acting jointly below and here as the Municipal Gas Group on behalf of their consumers,[3/] seek review under Section 19(b) of the Natural Gas Act. [4/]

1/ R. 11269

2/ R. 11357

3/ The Municipal Gas Group consists of the City of Chicago, Illinois, the City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee and the American Public Gas Association, all petitioners herein. As such, the group represents millions of consumers of natural gas throughout the United States.

4/ 15 U.S.C. §717r (1964).

STATEMENT OF THE CASE

Background. From the inception of regulation under the Natural Gas Act in 1938 to the present, the governing regulatory standard for gas produced by interstate pipeline companies and their affiliates has been individual company cost-of-service on a fair overall return. This regulatory principle, which the Supreme Court characterized as the "most generally accepted in the regulation of the levels of rates charged by both publicly and privately owned utilities" [5/] has been expressly confirmed by that Court in a number of leading decisions reviewing regulatory action by the Commission over the years, as an appropriate method of regulating the production of gas produced by pipelines and their affiliates, in order to "protect consumers against exploitation at the hands of natural gas companies." [6/] Prior to the present case, this standard for pipelines and their affiliates has been applied consistently by the Commission and courts regardless of the different, less precise, area rate regulatory treatment developed in 1960 for independent producers of gas due to the unique regulatory problems presented by that group, to which individual cost-of-service regulation was

---

5/ Permian Basin Area Rate Cases, 390 U.S. 747, 756 (1968).

6/ FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); Colorado Interstate Gas Co., v. FPC, 324 U.S. 581 (1945); Panhandle Eastern Pipe Line Co. v. FPC, 324 U.S. 635 (1945), discussed infra, pp. 15-19.

deemed inappropriate. The Commission itself in 1968 confirmed its long-standing regulatory policy by the citation of twenty-five cases demonstrating the individual cost-of-service basis of regulation for pipeline production to be "a long and well-established precedent:"

> In the only cases where the Commission departed from that rule, it was promptly reversed on appeal. On remand in those cases, and from that time, the Commission has universally applied the cost-of-service standard for pipeline-owned-production, and for production from affiliated companies. 7/

Assaults on the Commission's policy of pricing pipeline and affiliate produced gas at cost-of-service are not new, as noted by the Commission in its 1968 opinion.8/ Proponents of increased profits beyond cost-of-service for pipeline production, after the repulsion by this court in the 1950's of their attempts to have the Commission abandon cost-of-service in the City of Detroit, Mississippi River Fuel Corp. and Willmut Gas & Oil Co. cases,9/ next sought to convert the area rate concept (designed to meet

---

7/ Continental Oil Co., 39 F.P.C. 1034, 1044-45 (1968), affirmed sub nom., Cities Service Gas Co. v. FPC, 10th Cir. No. 151-68, Oct. 16, 1969, CCH utilities Law Reporter, Federal New Matters 11,093

8/ Id at 1044-45

9/ City of Detroit, Mich. v. FPC, 97 U.S. App. D.C. 260, 230 F.2d 810 (D.C. Cir. 1955), cert. denied, 352 U.S. 829(1956); Mississippi River Fuel Corp. v. FPC, 102 U.S. App. D.C. 238, 252, F.2d 619 (D.C. Cir. 1957), cert. denied, 355 U.S. 904, Willmut Gas and Oil Co. v. FPC, 112 U.S. App. D.C. 27, 299 F.2d 111 (D.C. Cir. 1962) See discussion infra, pp.20-23.

the unique regulatory problems of independent producers) 10/ to accomplish this end. Representatives of the Pipeline Production Group presented the Commission in 1963 with the claim that a similar method of regulation should be applied to pipeline and affiliate production. 11/

Proceedings below. Citing that it had been "repeatedly urged" to do so, the Commission by order of June 29, 1964 enlarged the pending Hugoton-Anadarko Area Rate Proceeding to add the issue as to whether pipeline and affiliated production should be regulated on an area rather than individual cost-of-service basis. 12/ The issue was severed from this proceeding on April 13, 1966 after the Commission determined that the evidence indicated that the Hugoton-Anadarko areas was not typical of the nation as a whole. 13/ The Commission noted that as of that time "no evidence has been introduced upon which a determination could be made of the impact upon the consumers of the various pipelines of substituting an area rate for one based upon each company's individual cost..." 14/ The Commission indicated

---

10/ Phillips Petroleum Co., 24 F.P.C. 537 (1960), affirmed sub nom., Wisconsin v. FPC, 112 U.S. App. D.C. 369, 303 F.2d 380 (D.C. Cir. 1961), affirmed, 373 U.S. 294 (1964).

11/ R. 3168-69

12/ 31 F.P.C. 1595 (1964).

13/ 35 F.P.C. 497 (1966), R.7110, 7111.

14/ Id.

that the issue was not that of finding a suitable method for regulating pipeline and affiliated produced gas but rather the propriety of abandoning the established cost-of-service method:

> Whether the Commission may or should depart from the cost-of-service method in fixing the price of pipeline produced gas is the precise issue to be determined... 15/

The proceeding was to be conducted in two phases. Phase I, which is the subject of this appeal, is directed to the pricing of gas produced from leases acquired subsequent to the date of this decision and taken into the pipelines' own system -- "new" gas. Phase II, which has not yet begun, will determine the pricing method to be attributed to gas taken into the system from leases acquired prior to the date of resolution of Phase I.

Hearings in the severed proceedings in Phase I styled as the Pipeline Production Area Rate Proceedings, Docket No. RP66-24, were commenced on September 27, 1967 and concluded on April 2, 1968. The hearing record before Presiding Examiner Allen C. Lande involved fifty volumes of transcript of 5670 pages, 16/ and 85 exhibits and items by reference. 17/

15/ Id.

16/ 1R.1 - 50 R. 5670.

17/ R. 5671-6174.

Presiding Examiner Lande issued his decision on March 3, 1969, which carefully reviewed the evidence of record.18/ The Examiner rejected area rate treatment and with minor modifications adhered to the cost-of-service method of regulation for new gas produced by the nation's interstate pipelines or their affiliates. The Examiner found that:

> The parties asking higher rates have failed to supply specific evidence sufficient to meet the standards of the City of Detroit case. 1/ "* * * that the rate increase is in fact needed and is no more than is needed, for the purpose ...."19/
>
> 1/ City of Detroit v. F.P.C., 230 F.2d 810 (CADC), certiori denied 352 U.S. 829
>
> *   *   *
>
> There are wide disparities in pipeline production costs with respect to their gas leases... If pipelines are put on a compulsory area rate for the future, some will reap windfalls. Others might experience substantial losses... [P] roducer losses may affect the

---

18/ R. 10045-10171.

19/ R. 10125.
Mr. Bass of the Staff concluded that given the facts of record on the growth and prosperity of the pipeline producers, it was difficult to find a warrant for additional incentive to maintain prudent production levels. (R. 4125-26.)

individual producer's ability and willingness to engage in subsequent exploration and development -- a private activity, whereas pipeline losses could affect their ability to perform their basic transportation functions -- a public duty. 20/

* * *

... a straight area rate for pipeline produced gas is likely to be more profitable than the same straight area rate for independent producers; it would also tend to unduly increase the cost of gas to their customers, and it would not benefit the public at large. While pipelines can produce new gas for about the same cost as the independent producers, they fail to rebut effectively the contentions of the Staff and the Municipal Group, that area rates would yield pipelines excessive profits and at the

---

20/ R. 10128.

The Examiner was obviously persuaded by the Staff's presentation that the lack of "parity" between the independent producer and the pipeline producers and affiliates militated against application of a straight area rate to pipeline produced "new" Gas. (E. g., R. 496, 503-504, 4425, 4426, 5013, 4258, 4257), and by the evidence submitted by El Paso and the Municipal Group demonstrating the wide variations in unit cost experience among pipeline producers and their affiliates. (R. 2164, 4018, 4200, 4357, 5275, 5908-10, 6001-03 6017-18, 10081-82). His finding also reflects the showing of the Municipal Group that although under area rate pricing some pipeline producers may be fortunate enough to be able to obtain an adequate return or even a windfall, others would be denied a fair return on net investment, and, therefore, would be unable to survive. (E. g., R. 3504-05, 5275-76, 5341-42, 10125, 10129). And in his conclusion of possible detriment to the consuming public through impairing the ability of a pipeline to carry on its public service transportation function, he was clearly influenced by the presentation of the Municipal Group that area rate valuation of pipeline-produced gas could force some pipelines to speculate and others to abandon their exploration and development activities to the detriment of the consuming public. (R. 3504-05, 3515-17, 3594, 3600.)

same time would eventually tend to unduly raise the cost of gas to the public. 21/

* * *

. . . In most instances such increase would benefit the pipeline stockholders much more than the gas consumers. Too much incentive would likely result in increased charges to the consumers. The advantages of encouraging pipelines to produce gas do not lend themselves to quantitative measurement. Heretofore the cost-of-service method of regulation, which the Commission has been applying to the pipeline produced gas, maintained a healthy competitive atmosphere, under which individual pipelines prospered;

. . . . . .

. . . . .

21/ R. 10129.

The Examiner's finding on this issue coincides with the position developed on the record that application of area rates to the pipelines would remove the incentive for the pipeline to bargain vigorously with the producers for the lowest attainable purchase prices, and thus would stifle, rather than encourage competition within the industry, contrary to the public interest. (Cf. R. 498, 499, 992, 1074) And the showing made that permitting the area rate of return to pipelines would produce a return on equity at least double the return currently permitted to them. (R. 495, 496, 6144).

where circumstances truly warranted it the pipelines produced adequate supplies of their own gas . . . 22/

* * *

The Staff and the Municipal Group submitted into the record convincing data show that application of the straight area rates to new gas produced by the pipelines would result in windfalls to the pipeline stockholders coupled with correspondingly higher charges to the consumers . . . 23/

22/ R. 10130.
The Examiner's conclusions relating to the "healthy" competitive status of the industry under the cost-of-service regulatory method is abundantly supported on the record. The Municipal Group presented evidence of the growth and prosperity of the pipelines under the current regulatory policy. (E.g., R.5736, 5809, 5810, 5812, 5815, 6124). The Group's presentation stressed the particular significance of the fact that pipeline increases in exploration and development activities continued through the 1955-1962 period (R. 5727, 6124), during which time de facto area rates were in effect for many independent producers. (R. 10125). Also considered significant in this context was the fact of record that the pipeline producers are in a healthier reserve production position than the independent producers. (R. 5740, 5745, 5809 (col. II), 5815 (Col. 7) The Municipal Group largely related the success of this regulatory method to its flexibility. If it proved to be economically and managerially prudent to acquire production properties, the pipelines would be free to do so with the resulting benefit of full cost underwriting by the consumer. If the position of the pipeline makes it imprudent to acquire gas through its own production operation, the pipeline can obtain its supply solely through purchase contracts with independent producers. (R. 994, 997-98).

23/ R. 10131. See references note 20, 21 supra.

* * *

> . . . The Municipal Group, as well as the Staff, have very properly pointed out that [completely exluding tax benefits from production from cost-of-service computations] has been clearly rejected by the courts and by this Commission. _E.g._, _Cities Service Gas Co._, 30 FPC 158, 162, _set aside sub nom._ _Cities Service Gas Co._ v. _F.P.C._, 337 F.2d 97 (CA10, 1964) but approved in _F.P.C._ v. _United Gas Pipeline Co._ 386 U.S. 237 (1967) . . . 24/

The modifications in the application of cost-of-service adopted by the Examiner are (a) that the pipeline producer and the consumers split the tax benefits attributable to the deductions for percentage depletion and for intangible well drilling costs, and (b) that ten percent of the total volumes produced in one year by an affiliate may be priced at area rates.

The Municipal Gas Group supported affirmance of the Examiner's decision by the Commission insofar as it maintained cost-of-service regulation, but excepted to the modifications to that regulatory method proposed by the Examiner. 25/

The Commission in Opinion 568 26/ held completely contrary to the Examiner on all points. The Commission concluded that

---

24/ R. 10133.
See in support of this finding, _e.g._, R. 491, 510, 3989, 4049, 4065, 5421, 5673.

25/ R. 10499

26/ R. 11269

(1) straight area rates should govern the cost attributable to gas produced by pipelines or their affiliates; (2) the same overall rate of return permitted the independent producers should be permitted to the pipelines and their affiliates; and (3) that the pipelines should be permitted to retain the benefit of tax credits by not having them considered in fixing the tax allowance on their transmission operations.

The basic point stressed by the Commission for its decision was an assertion of an "apparent gas shortage" admittedly not established or litigated on the record of the case:

> 7. This is a turning point in the regulation of pipelines owning their own reserves, but it follows closely upon the development of area regulation for the independent producers and a changing picture in the gas supply situation as shown by the record and other facts coming to our attention. In the light of an apparent gas shortage we are concerned whether the pipelines will make an increased effort to explore for and develop new gas reserves . . . To attain these ends it may be incumbent upon us to modify traditional approaches to regulation with respect to pipeline production in order to provide a regulatory climate conducive to an aggressive pipeline exploration program.
>
> * * *
>
> 14. We arrive at this conclusion at a time when there are indications of a shortage of gas and a threat of a greater shortage in the future. For instance, for the first time the American Gas Association reported that in 1968 net gas production exceeded the reserves added resulting in a decline in total proved reserves from 292.9 trillion cubic feet to 287.3 trillion cubic feet by the end of 1968.[8/]

> 15. While the 1968 figures are not in the record . . .
>
> ---
>
> 8/ AGA Committee on Annual Gas Reserves; Report issued April 7, 1969. 27/

The Commission did not directly overturn the express findings by the Presiding Examiner against straight area rates based on the record.

Petitions for Rehearing were denied on December 5, 1969 in Opinion No. 568-A[28], thus terminating the proceedings on the Commission level. The Municipal Gas Group subsequently filed the present appeal to this court.

27/ R. 11281, 11284.

28/ R. 11357.

ARGUMENT

I. ON THIS RECORD EXISTING LEGAL STANDARDS COMPEL THE CONTINUANCE OF COST-OF-SERVICE REGULATION OF THE GAS PRODUCED BY INTERSTATE PIPELINE COMPANIES OR ACQUIRED FROM THEIR AFFILIATES.

A. The cost-of-service standard has been applied to pipeline and affiliate production by the Commission and the courts since enactment of the Natural Gas Act.

The initial case to consider the proper regulatory treatment of gas produced by interstate pipeline companies subject to regulation by the Federal Power Commission arose soon after the enactment of the Natural Gas Act upon complaints filed in 1938 by the Cities of Cleveland and Akron, Ohio, against Hope Natural Gas Company and was finally adjudicated in 1944 by the Supreme Court in FPC v. Hope Natural Gas Company. [29/] The Hope Company had extensive producing properties supplying its interstate transmission facilities. The Commission established a rate based on "actual legitimate cost" of the Company's property including the producing properties, to which, after deducting for depreciation, were added sums for useful inoperative acreage. For annual operating costs, the Commission determined amounts for out-of-pocket expenses, annual depletion and depreciation, exploration and development costs, and added sums for a future increase in exploration and development costs. It set an overall return on the rate base of 6 1/2 percent.

29/ 320 U.S. 591 (1944).

The Supreme Court upheld the Commission's cost-of-service regulation. The Court held that the Commission in undertaking its statutory duty "to protect consumers against exploitation at the hands of natural gas companies" could properly use the prudent investment cost-of-service method of regulation rather than basing regulation on the estimated fair value of the gas or company's properties. The Court made it clear that the Commission can allow an appropriate return for gas production in determining the pipeline's overall rate of return under cost-of-service principles:

> It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. . . 30/

30/ 320 U.S. at 615.

The following year, 1945, the Supreme Court considered another ruling by the Commission applying cost-of-service regulation to gas produced by an affiliate of an interstate pipeline company in Colorado Interstate Gas Co. v. FPC. 31/ This case involved the regulation of the rates of the Canadian River Gas Company and its affiliate, the Colorado Interstate Gas Company. Canadian produced from its own properties all of the gas which it transported through a transmission line in Texas and New Mexico, a large portion of which it sold to Colorado Interstate at Clayton, New Mexico, which company in turn made sales for resale to distributing companies in Colorado. The Commission determined a rate base which included Canadian's production and gathering properties as well as its interstate transmission system, and allowed an overall 6 1/2% rate of return thereon. The Commission made an allowance for working capital to enable Canadian to carry on its production and gathering operations, and made an allowance for Canadian's operating expenses which included the cost of producing and gathering natural gas. The Court rejected a claim by Canadian and Colorado Interstate that the Commission should have set the rates for company produced gas based on the "fair field price" or "fair market value, as a commodity, of the gas," as contrary to the similar position advance by the State of West Virginia in the Hope Natural Gas Co. case:

31/ 324 U.S. 581 (1945)

When a natural-gas company which owns producing properties or a gathering system is restricted in its earnings by a rate order, the value of all of its property is affected. Congress of course might have provided that producing or gathering facilities be excluded from the rate base and that an allowance be made in operating expenses for the fair field price of the gas as a commodity. Some have thought that to be the wiser course. But we search the Act in vain for any such mandate. The Committee Report stated that the Act provided "for regulation along recognized and more or less standardized lines" and that there was "nothing novel in its provisions." H. Rep. No. 709, 75th Cong., 1st Sess. p. 3. Certainly the use of a rate base which reflects the property of the utility whose rates are being fixed has been customary. 2 Bonbright, Valuation of Property (1937) c.XXX; Smith, The Control of Power Rates in the United States and England (1932); 159 The Annals 101. Prior to the Act that method was employed in the fixing of the rates of gas, as well as electric utilities. See Willcox v. Consolidated Gas Co., 212 US 19, 53 L ed 382, 29 S Ct 192, 48 LRA (NS) 1134, 15 Ann Cas 1034; Cedar Rapids Gas Light Co., v. Cedar Rapids, 223 US 655, 56 L ed 594, 32 S Ct 389; Newark Natural Gas & Fuel Co. v. Newark, 242 US 405, 61 L ed 393, 37 S Ct 156, Ann Cas 1917B 1025; Railroad Commission v. Pacific Gas & E. Co. 302 US 388, 82 L ed 319, 58 S Ct 334; Lone Star Gas Co. v. Texas, 304 US 224, 82 L ed 1304, 58 S Ct 883. We do not say that the Commission lacks authority to depart from the rate-base method. We only hold that the Commission is not precluded from using it. There are ample indications throughout the Act to support that view. 32/

32/ 324 U.S. at 601-602.

In a separate case, decided the same day, Panhandle Eastern Pipe Line Co. v. FPC, 33/ the Court upheld a Commission decision including Panhandle's producing facilities on a cost basis in the Company's rate base with a 6 1/2% overall return and rejected Panhandle's claim that they be included at market value:

> This phase of the case is controlled by Canadian River Gas Co., v. Federal Power Commission, 324 US 581, ante, 1206, 65 S Ct 829, supra. We need not repeat what we said there. It is clear that the value of producing properties and gathering facilities is affected whenever rates are fixed. This is inevitably true whether the leaseholds are put into the rate base or whether as petitioner urges the gas is valued as a commodity. That result is not avoided unless Congress puts a floor under production properties and gathering facilities of natural gas companies and fixes a minimum return on them. That Congress has not done. 34/

Another attempt was made after a change in membership of the Commission in the early 1950's, to seek to have the Commission abandon the cost-of-service method of regulation for pipeline-produced gas affirmed by the Supreme Court in the Hope, Colorado Interstate and Panhandle cases. In Panhandle Eastern Pipe Line Co., 35/ the Commission, acting through a bare majority consisting of Jerome K. Kuykendall, Nelson Lee Smith, and Seaborn L. Diby, 36/ sought to change the established cost-of-service method of regulating pipeline production. In so doing, the majority recognized that the rate base approach in pricing

---

33/ 324 U.S. 635, 648 (1945)

34/ 324 U.S. at 649.

35/ 13 F.P.C. 53 (1954)

36/ Commissioner Doty dissented on other grounds.

Panhandle's produced gas "has been the Commission's long-established policy, which has been sanctioned by the courts, including the Supreme Court of the United States." 37/ The Commission, however, decided to "re-examine" the issue and concluded that the pipeline should "receive for the gas it produces a price reflecting the weighted average arm's length payments for identical natural gas in the fields . . . where it is produced . . ." 38/ Commissioner Draper in a well-reasoned dissent, concluded:

> I have followed conscientiously the reasoning advanced for this reversal of a policy which this Commission has consistently employed for about 15 years in the regulation of natural gas companies, but I cannot convince myself that in the present state of the law and the clear decisions of the courts thereunder as I understand them, we can legally inaugurate such a basic and far-reaching change of position on this question. Nor do I believe such a policy should be inaugurated aside from its doubtful legality . . . (13 F.P.C. at 124-125.)

On appeal by the City of Detroit and County of Wayne, the Court of Appeals for the District of Columbia Circuit reversed the Commission. City of Detroit, Michigan v. FPC, 39/ While the court did not consider the Commission bound to the traditional rate-base method of regulation for pipeline produced gas, it held that the contentions posed by the Commission for abandonment of

---

37/ 13 F.P.C. at 64.n.13.

38/ 13 F.P.C. at 76

39/ 97 U.S. App. D.C. 260, 230 F.2d 810 (D.C. Cir. 1955), *cert. denied*, 352 U.S. 829 (1956).

that system did not satisfy the primary aim of the Natural Gas Act " 'to protect consumers against exploitation at the hands of natural gas companies.' " As to the Commission contention that the traditional rate-base system does not sufficiently encourage the discovery and development of gas this was rejected on the following grounds:

> If the Commission contemplates increasing rates for the purpose of encouraging exploration and development, or the ownership by pipeline companies of their own producing facilities, it must see to it that the increase is in fact needed, and is no more than is needed, for the purpose. Further than this we think the Commission cannot go without additional authority from Congress.
>
> The amount allowed Panhandle for the encouragement referred to is not shown to meet this test by any evidence and findings. Of course the rate increase attributable to producing properties might have a tendency to encourage their ownership, and perhaps also the development of new sources of production, as an even greater increase also might do. But the question is whether a lesser amount would suffice. The amount here allowed is not brought into relationship by the evidence and findings with the purposes for which it is granted except that it affords a larger revenue to Panhandle than otherwise it would have. This is not an adequate basis for bringing the resulting rates within the "just and reasonable" standards of the Act. The mere fact that the field price method is used does not vindicate the rates. Its use can be justified only in terms of a demonstrated public interest. In this case an allowance for the desired purposes, assuming they are valid, could be included without resort to the field price system. When the latter method is used the evidence and findings must show that the increase in rates thus caused is no more than is reasonably necessary for the purposes advance for any increase. Since there is nothing in these proceedings from which such a conclusion could be drawn, they are fatally defective. In other words, we do not substitute "our

> opinions for the expert judgment of the administrators to whom Congress entrusted the decision." Federal Power Commission v. Hope Natural Gas Co., 320 US at page 615 64 S. ct at page 294. We simply say that if the Commission is now to abandon the treatment historically accorded pipeline-produced gas in rate making on the ground that the ultimate public interest will be better served thereby, the Commission should justify it on the record. (230 F. 2d at 817-818.)

The court then added an important caveat that even if the Commission properly had found such evidence, this would not necessarily satisfy the Act:

> An additional explanation of our view is desirable. We should not be understood to say that whenever the Commission does establish the necessary relationship between means and end, a prescribed rate increase will be lawful. In view of the primary orientation of the Act toward the maintenance of low prices for the consumer, we do not preclude the possibility that a rate increase might be unlawful even though no lower rate could encourage gas production by pipeline companies. On this record, however if the necessary relationship had been shown we would not consider the rates so high as to be unlawful. (230 F. 2d at 818.)

While the evidence in the case showed a comparision of the impact on consumers of switching to a new system, the court strongly emphasized that the showing of the comparison was important:

> Furthermore, it is seen that when we refer to an "increase" we mean an increase in the rates above those which would result from use of the conventional rate-base method. For, though we hold that method not to be the only

> one available under the statute, it is essential in such a case as this that it be used as a basis of comparison. It has been . . . repeatedly approved by the courts, as a means of arriving at lawful -- "just and reasonable" -- rates under the Act. Unless it is continued to be used at least as a point of departure, the whole experience under the Act is discarded and no anchor, as it were, is available by which to hold the terms "just and reasonable" to some recognizable meaning. (230 F. 2d at 818-819.) 40 /

In 1961, the Commission entered its decision on the remand in the City of Detroit case, as well as on a new Panhandle rate filing, and held that Panhandle's production properties must be regulated on a cost basis. 41/ The Commission under Chairman Kuykendall ruled that Panhandle had not established by any convincing evidence why an allowance in addition to that provided by the cost rate base evidence should be made:

> In the City of Detroit case, as has been often repeated, it was said that the rate base method must be used as a basis of comparison and as a point of departure. The court said that if the Commission contemplates increasing rates for the purpose of encouraging exploration and development or the ownership by pipeline companies of their own producing facilities, it must see that "the increase is in fact needed, and is no more than is needed, for the purpose." . . .

40/ The City of Detroit case was followed in subsequent decisions by the court. Mississippi River Fuel Corp. v. FPC, 102 U.S. App. D. C. 238, 252 F. 2d 619 (D. C. Cir. 1957), cert denied. 355 U.S. 904; Willmut Gas and Oil Co. v. FPC, 1120 U.S. App. D.C. 27, 299 F.2d 111 (D.C. Cir 1962).

41/ Panhandle Eastern Pipe Line Co., 25 FPC 784, 785, (1961); Panhandle Eastern Pipe Line Co. 25 FPC 787 (1961).

In the first place, we do not think controlling Panhandle's discussion of the history of its exploration and development operations as affected by the issuance of Opinion No. 269 and the subsequent denial of certiorari by the Supreme Court. In the light of the present record, discussed further below, Panhandle's history does not show how much is needed to encourage exploration and development. Furthermore, we are not able to found an additional allowance for the produced gas on a hypothetical program of expansion that Panhandle says it should have undertaken during the past refund period but did not do so, even if we assume that such a program was needed.

* * *

. . . While it may be true that the commodity value proposed by Panhandle effect savings over the prices that Panhandle might have to pay in the market for additional gas, the proposed commodity value would cost the consumer more than an allowance made on the cost basis for Panhandle's own supplies of gas. (25 F.P.C. at 792, 793.)

On appeal by Panhandle, this court affirmed the Commission.[42/]

The established regulatory treatment of gas produced by interstate pipeline companies and their affiliates was reaffirmed in Opinion No. 542 issued June 27, 1968 in Continental Oil Company.[43/] In that case the Commission reviewed the long-standing regulatory rule regarding production by pipelines and their affiliates and concluded that:

42/ Panhandle Eastern Pipe Line Co. v. FPC, 113 U.S. App. D. C. 94, 305 F.2d 763 (D. C. Cir. 1962), cert. denied, 372 U.S. 916 (1963).

43/ 39 FPC 1034, 1044-45 (1968), affirmed sub. nom. Cities Service Gas Co. v. FPC, 10th Cir. No. 151-68, October 16, 1969, CCH Utilities Law Reporter, Federal New Matters 11,093.

> There is no question that had Gas Co. retained ownership of the producing properties, its allowance for gas in any rate case litigated to a final conclusion would have been computed on a cost-of-service basis. This basis had a long and well-established precedent of which Gas Co. was, or should have been, well aware prior to any transfer of the producing property . . . 44/

The Court of Appeals for the Tenth Circuit affirmed on October 16, 1969, 45/ upholding cost-of-service treatment for gas originally produced by a regulated pipeline even though the leases had been sold to a non-affiliated company, to protect consumers against unjustified profits. The Court's opinion is also significant in that it reveals the substantial impact on consumers in higher gas prices in that case of a shift from cost-of-service to area rates, and in the re-emphasis of the court of the long-standing distinctions between pipeline production and independent producer production.

B. The record in this case does not contain specific evidence sufficient to meet the standards of the City of Detroit case for a deviation from the recognized individual cost-of-service standard, and the Commission's attempts to avoid or distinguish that case are fallacious.

It is significant to note that with respect to the arguments advanced by the Pipeline Production Group for area rates and the decision of the Commission below accepting these arguments, this proceeding has become merely a replay of the 1954 Panhandle

---

44/ Id.

45/ Id.

Eastern Pipe Line Company case 46/ which was reversed by this court on appeal in City of Detroit v. FPC. 47/ The pipeline interests in Panhandle, in an attempt to obtain a higher price for pipeline-produced gas also employed the now familiar tactic of claiming a marked decline in the reserve-production ratio as evidence of a need for a change. 48/ It was the pipeline interests position that if pipeline production was priced at weighted average field price, instead of cost-of-service, exploration and development would be encouraged and the gas supply situation would improve. 49/

This court in the leading City of Detroit case rejected the contention that the traditional cost-of-service system may be abandoned to encourage the discovery and development of gas in the absence of clear and precise evidence that the increase will have that effect:

> . . . the Commission . . . must . . . always, relate its action to the primary aid of the Act to guard the consumer against excessive rates. If the Commission contemplates increasing rates for the purpose of encouraging exploration and development, or the ownership by pipeline companies of their own producing facilities, it must see to it that the

---

46/ 13 F.P.C. 53 (1954)

47/ 97 U.S. App. D.C. 260, 230 F.2d 810 (D.C. Cir. 1955), cert. denied, 352 U.S. 829 (1956)

48/ 13 F.P.C. at 74-76

49/ Id. at 62-76

> increase is in fact needed, and is no more than is needed, for the purpose. Further than this we think the Commission cannot go without additional authority from Congress. 50/

The court concluded that Panhandle had not shown the need for a change:

> The amount allowed Panhandle for the encouragement referred to is not shown to meet this test by an evidence and findings. Of course the rate increase attributable to producing properties might have a tendency to encourage their ownership, and perhaps also the development of new sources of production, as an even greater increase also might do. But the question is whether a lesser amount would suffice. The amount here allowed is not brought into relationship by the evidence and findings with the purposes for which it is granted except that it affords a larger revenue to Panhandle than otherwise it would have. This is not an adequate basis for bringing the resulting rates within the 'just and reasonable' standards of the Act. 51/

The court then proceeded to set forth the criteria which had to be met if deviation from the current regulatory method was to be permitted, and suggested that any needed incentive for exploration and development could be provided within the cost-of-service framework:

> . . . The mere fact that the field price method is used does not vindicate the rates. Its use can be justified only in terms of a demonstrated public interest. In this case an allowance for the desired purposes, [encouragement of exploration and development] assuming they are valid,

---

50/ 97 U.S. App. D. C. at 267, 230 F.2d at 817.

51/ 97 U.S. App. D. C. at 267, 230 F.2d at 817-818 (footnote omitted ; emphasis added).

> could be included without resort to the field price system. When the latter method is used the evidence and findings must show that the increase in rates thus caused is no more than is reasonably necessary for the purposes advanced for any increase. Since there is nothing in these proceedings from which such a conclussion could be drawn, they are fatally defective . . . if the Commission is [redacted] to abandon the treatment historically accorded pipeline-produced gas in rate making on the ground that the ultimate public interest will be better served thereby, the Commission should justify it on the record. 52/

The Presiding Examiner, after hearing all of the extensive evidence, expressly found that

> The parties asking higher rates have failed to supply specific evidence sufficient to meet the standards of the *City of Detroit* case. 1/ "***that the rate increase is in fact needed and is no more than is needed, for the purpose . . ." 53/

The Commission in Opinion No. 568 below did not directly disagree with the Examiner's finding based on the record, but submitted with respect to the *City of Detroit* criteria that, assuming *arguendo*, its applicability:

> . . . clearly the 'anchor' the court here felt should be the 'point of departure' in moving to a pricing system other than the conventional rate-base method . . . lies in the approved just and reasonable area rates for independent producers. 54/

52/ 97 U.S. App. D.C. at 268, 230 F.2d at 818. (footnotes omitted); emphasis added.

53/ R. 10125.

54/ R. 11284.

The Commission's arbitrary conclusion that the City of Detroit criteria for departure from the current method of pricing pipeline-produced gas is met because area rates have been adjudicated just and reasonable with respect to independent producers is indeed strained and completely contrary to law and fact.

1. The record in the present case, as found by the Presiding Examiner, does not justify switching from cost-of-service for pipeline production to area rates.

The alternative to cost-of-service proposed in this proceeding cannot on this record satisfy any of the criteria established for change, namely, the need for a change; the amount of change required; the ability of the alternative method to meet the need; and the impact of the alternative method on the pipeline and the consumer measured against the performance of the current regulatory method. Therefore, it became necessary that the Commission in order to implement its result find a basis for change outside of the record. The conclusion of the Commission that the rate treatment considered just and reasonable for independent producers is ipso facto just and reasonable for pipeline producers reflects the Commission's total misunderstanding of the legal principles involved in the City of Detroit case.

The purport of the criteria established by this court in City of Detroit is to assure that the evidentiary facts of record before the Commission support a need for a change and show that the method adopted will best meet the need without sacrificing either the interest of the utility in a stable, sufficient return or the interest of the consumer in just and reasonable rates. A change of

regulatory method for pipeline producers must not and cannot be based upon a record from another proceeding, dealing with an entirely different segment of the gas industry, a segment which Examiner Lande found from this record was not comparable to the pipeline segment either in capital structure or in the element essential to group pricing, -- cost comparability. The change must be based upon the record as made by and related to pipeline producers. It must flow from this record. It does not.

In construing the case to satisfy the criteria because area rates have been adjudicated just and reasonable for independent producers, the Commission has avoided its responsibility to use cost-of-service as a departure point for a comparison with area rate pricing for pipeline production and to demonstrate that a need for a change exists and that the area rate system will meet that need better than the cost-of-service system and at the same time provide just and reasonable rates for the consuming public. The Commission has not shown and cannot show on the present record a comparison necessary to justify abandonment of cost-of-service.

The Commission speculatively concludes that area rate treatment of pipeline-produced gas will encourage and result in intensified exploration by the pipeline producers. There is no evidentiary basis for such a conclusion. The only certainties from the record are:

(1) that of those who choose to produce, the low-cost producers will receive a higher price for their production; 55/

55/ R. 10126, 10130

(2) that area rate pricing will tend to discourage some existing producers or potential producers who may not be in the position to assume the risk inherent in exploration activities 56/ or who fail to obtain an exception from the Commission as to area rate applicability; 57/

(3) that forcing a segment of the pipelines to remove themselves from production reduces proportionately the impact the presence of such producers could have in increasing the reserve gas supply, and reduces the effectiveness of the pipelines' ability to utilize its own production on an optional, economic basis (swing) for the benefit of its consumers and particularly to use it as a bargaining aid in keeping the price of gas down; 58/

(4) that selection of area rate pricing for pipeline-produced gas demonstrates that the Commission has arbitrarily abdicated its authority to disallow excessive or imprudent costs or to otherwise impose regulatory restraint against excessive pricing; and

---

56/ R. 10129, R. 3600-01; R. 3717

57/ The following general specification of circumstances that would justify special relief from area rate pricing is taken from the Commission's opinion in the Southern Louisiana Area Rate Cases as discussed in Southern Louisiana Area Rate Cases v. FPC, 5th Cir. (Civil No. 27492 et al, March 19, 1970.):

> . . . certain principles have been established. Overall high cost of service of an individual producer is not a ground for relief. The fact that current revenue from a particular well is less than the costs of continuing its production is a ground for relief. The fact that a producer can obtain a higher price elsewhere is not a ground for relief . . ." (Slip Op. at page 15).

58/ R. 10130; R.3504, 3515-17, 3524-25; R. 3594, 3600.

(5) under cost-of-service the pipelines have a high level prosperity, including a higher reserve-production ratio than have the independent producers under area rates. 59/

On the other hand, the record clearly shows the benefits of cost-of-service for pipeline production, which were ignored by the Commission in its quest to allow the pipeline producers unjustified rates:

(1) that individual cost-of-service pricing adequately compensates the exploration and development function of the pipeline company by permitting pipeline producers and affiliates the incentives inherent in allowing them actual production costs plus a fair rate of return on the individual overall investment;

(2) that in determining the rate of return for each individual pipeline company, the costs of successful wells are added to the

---

59/ R. 10127-28; Ex No. 21, Sch. 1, and Sec. 7; R. 5809, 5816; Ex No. 6, p8,, R. 5744.

The Commission acknowledges that there is no assurance that the "incentives" it provides will be utilized to bring forth additional pipelines to plow back their tax credits into production operations; it is quite possible that these credits would be utilized in a venture bearing no relation to the need for additional gas reserves. (R. 11290) Further the Commission fails to require dedication of new gas supplies in the public interest. The Commission expresses the hope that its regulatory method will generate increased exploration and development activity and also insure the consumer interests the benefit of any increased gas supply. However, the Commission merely "anticipates" prompt dedication to the interstate consumer of new gas reserves; it makes no attempt to insure such dedication, and thereby to prevent alienation of new gas reserves from the interstate consumer the Opinion purports to benefit. (R. 11290)

rate base on which a return can be earned while the costs charged to unsuccessful wells are considered as an expense of doing business and an allowance for these expenses is granted;

(3) that since profit and incentive to produce gas are equated with return on equity investment, 60/ the incentive to produce gas can be augmented, when necessary, by increasing the rate of return, or, as developed in greater detail below by permitting a special individualized exploration and development allowance geared to assuring, when necessary, that gas will be produced where it is needed;

(4) that all "prudent" production costs are borne by the pipeline's consumers. The prudence and reasonableness of E&D expenditures of a pipeline company are open to question in rate increase or decrease hearings, initiated at the behest of the company or by the Commission on its own motion. 61/ The Commission, therefore, possesses the authority to disallow any imprudent, inefficient, unreasonable or otherwise unwarranted exploration and development expenses. And thus to the extent that the Commission chooses to exert the full force of its regulatory powers, and not arbitrarily abdicate them, the pipeline is restrained from making imprudent capital expenditures;

60/ Bluefield Co. v. Public Service Com., 262 U.S. 679 (1923). El Paso Natural Gas Co. v. FPC 281, F.2d 567, 572 (5th Cir. 1960), cert denied, 366 U.S. 912 (1961); City of Detroit v. FPC, 97 U.S. App. D. C. 260, 263-65, 230 F. 2d 810, 817-819, cert. denied, 352 U.S. 829 (1956); Phillips Petroleum Co., 24 FPC 537, 575-76 (1960).

61/ 15 U.S. C. §717d.

(5) that the consumer underwrites the costs of discovery and development but he also shares in whatever benefits result from production. For example, the possibility of lower rates through, in part, the application to the transmission and delivery phase of the pipeline operation of any tax benefits spilling over after application of the tax benefits resulting from statutory depletion percentage and intangible well-drilling cost allowance to the production phase of the pipeline operation.

(6) that cost-of-service is a flexible managerial tool. If it is economically and managerially prudent to acquire production properties, the pipeline can do so with the resulting benefit of full cost underwriting by the consumer. If acquisition of gas through production is imprudent, the pipeline can obtain its supply through purchase.

The pipeline has a built-in incentive to explore for gas because of its relationship to the earning power of a substantial transmission investment. In the past this incentive, plus an increase, when required, in the rate of return on the pipeline's equity investment, has proven sufficient to stimulate necessary exploration and development. However, if the Commission is ever of the opinion that the continued vitality of the natural gas industry necessitates that the pipelines undertake exploration and development activities in addition to those found necessary or desirable in the past, to encourage gas production at the time and in the place needed by the pipelines, the Commission possesses the authority and the machinery, without departing from the present

regulatory method, to make a generous individualized allowance for seeking out and developing "new" gas reserves. This allowance would be tailored to the particular history and needs of the specific pipeline. In this manner, the Commission, without departing from the current regulatory method and without the adverse affects of area rates, would insure that the seeking out and development of gas resources would in fact be accomplished and could insure further that the resources would be developed where and when needed.

2. There is no legal basis for applying area rates designed for independent producers to the different situation of pipeline producers.

In Permian Basin Area Rate Cases,[62] the Supreme Court noted that factors of administrative convenience required experimentation with a different regulatory technique from cost-of-service.[63] The Court carefully delineated the scope of its opinion upholding the validity of the Commission's area rate ruling in Permian as applicable only to the regulation of "independent producers". It cited the definition of independent producers from its earlier 1954 Phillips decision as those "that do not engage in the interstate transmission of gas from producing field to consumer markets and [are] not affiliated with any

---

62/ 390 U.S. 747 (1968)

63/ 390 U.S. at 757-58.

interstate natural-gas pipeline Co." In so doing, the Court carefully distinguished interstate pipelines having production operation, which had long been classified as public utilities, subject to individual cost-of-service regulation:

> The circumstances that led ultimately to these proceedings should first be recalled. The Commission's authority to regulate interstate sales of natural gas is derived entirely from the Natural Gas Act of 1938. 52 Stat. 821. The Act's provisions do not specifically extend to producers or to wellhead sales of natural gas, and the Commission declined until 1954 to regulate sales by independent producers 6/ to interstate pipelines. Its efforts to regulate such sales began only after this Court held in 1954 that independent producers are "natural gas compan[ies]" within the meaning of §2(6) of the Act. 15 USC §717a(6); Phillips Petroleum Co. v. Wisconsin, 347 US 672, 98 L Ed 1035, 74 S Ct 794. The Commission has since labored with obvious difficulty to regulate a diverse and growing industry under the terms of an ill-suited statute.
>
> * * *
>
> The Commission initially sought to determine whether producers' rates were just and reasonable within the meaning of §§4(a) and 5(a) by examination of each producer's costs of service. Although this method has been widely employed in various rate-making situations, it ultimately proved inappropriate for the regulation of

6/ Independent producers are those that do "not engage in the interstate transmission of gas from the producing fields to consumer markets and [are] not affiliated with any interstate natural gas pipeline company. "Phillips Petroleum Co. v. Wisconsin, 347 US 672, 675, 98 L Ed 1035, 1044, 74 S Ct 794.

independent producers. Producers of natural gas cannot usefully be classed as public utilities. 11/

11/ It has been said that "the primary, even though not the sole, distinguishing feature of a public utility enterprise is to be found in a technology of production and transmission which almost inevitably leads to a complete or partial monopoly of the market for the service." Bonbright, supra, at 10. See also Sunray Oil Co. v. FPC 364 US 137, 160, 4 L Ed 2d 1623, 1643, 80 S Ct 1392 (dissenting opinion). 64/

Furthermore, the present record shows that the pipeline' cost variances are quite different from those of the independent producers. 65/ For the Commission to simply apply area rates to the pipeline producers, when there is no record basis for comparibility of the two groups on the basis of cost evidence of record, is contrary to an established line of cases holding that administrative agencies may calculate rates for a regulated class provided they have before them evidence which is representative and ample in quantity to measure with appropriate precision the financial and other requirements of the pertinent parties. See Tagg Bros. v. United States; 66/ Acker v. United States, 298 U.S. 426; 67/

64/ 390 U.S. at 755-56

65/ R. 4200, 5275, 4357, 4355, 5978; See supra pp. 8-9.

66/ 280 U.S. 420

67/ 298 U.S. 426

United States v. Corrick;[68] Compare New England Divisions Case;[69] United States v. Abilene & S.R. Co.;[70] New York v. United States;[71] Chicago & N. W. R. Co. v. A.T. & S.F.R. Co.[72]

68/ 298 U.S. 435

69/ 261 U.S. 184, 196-199

70/ 265 U.S. 274, 290-291

71/ 331 U.S. 284

72/ 387 U.S. 326, 341

C. The deviation from the cost-of-service method of pricing pipeline produced gas is of questionable legal permissibility.

The question of whether it is legally permissible to deviate from the established cost-of-service method of regulating pipeline produced gas has never been resolved. Dicta in Colorado Interstate Gas Co. v. FPC [73/] gives strong support to the proposition that deviation may be impermissible without amendment of the Natural Gas Act. In that case the Supreme Court rejected a claim that the Commission should have set the rates for company produced gas based on the "fair field price" or "fair market value, as a commodity, of the gas," as contrary to the similar position advanced by the State of West Virginia in the Hope Natural Gas Co. case:

> When a natural-gas company which owns producing properties or a gathering system is restricted in its earnings by a rate order, the value of all of its property is affected. Congress of course might have provided that producing or gathering facilities be excluded from the rate base and that an allowance be made in operating expenses for the fair field price of the gas as a commodity. Some have thought that to be the wiser course. But we search the Act in vain for any such mandate. The Committee Report stated that the Act provided "for regulation along recognized and more or less standardized lines" and that there was "nothing novel in its provisions."

73/ 324 U.S. 581 (1945).

> H. Rep. No. 709, 75th Cong. 1st Sess. p 3. Certainly the use of a rate base which reflects the property of the utility whose rates are being fixed has been customary. 2 Bonbright, Valuation of Property (1937) c. XXX; Smith The Control of Power Rates in the United States and England (1932); 159 The Annals 101. Prior to the Act that method was employed in the fixing of the rates of gas, as well as electric, utilities. 74/

The legal permissibility of deviation was also questioned by Commissioner Draper in his well-reasoned dissent in the Panhandle Eastern Pipeline Company 75/ proceeding. Commissioner Draper whose analysis in Panhandle mirrored the course this Court pursued in reversing the Commission in City of Detroit, 76/ concluded:

> I have followed conscientiously the reasoning advanced for this reversal of a policy which this Commission has consistently employed for about 15 years in the regulation of natural gas companies, but I cannot convince myself that in the present state of the law and the clear decisions of the courts thereunder as I

74/ 324 U.S. at 601-602; emphasis added.

75/ 13 F.P.C. 53, 124-125 (1954).

76/ City of Detroit, Michigan v. FPC, 97 U.S.App.D.C. 260, 230 F.2d 810 (D.C. Cir. 1955), reversing sub nom., Panhandle Eastern Pipeline Co., 13 F.P.C. 53 (1954).

> understand them, we can legally inaugurate such a basic and far-reaching change of position on this question. Nor do I believe such a policy should be inaugurated aside from its doubtful legality 77/. . . .

The language employed by this Court in City of Detroit reflects the legal uncertainties relating to deviation from cost-of-service. After establishing that the Commission had not shown that the increase which would result from the alternative (field price) proposed to cost-of-service is needed and is no more than is needed to fulfill those purposes motivating the Commission to depart from the traditional regulatory method 78/ the Court then added an important caveat. The Court concluded that even if the Commission properly had found such evidence, this would not necessarily satisfy the Act:

> An additional explanation of our view is desirable. We should not be understood to say that whenever the Commission does establish the necessary relationship between means and end, a prescribed rate increase will be lawful. In

---

77/ 13 F.P.C. at 124-125.

78/ Of particular significance to this issue is the observation of the court that "In this case an allowance for the desired purposes, assuming they are valid, could be included without resort to the field price system." 97 U.S.App. D.C. at 266, 230 F.2d at 817-818.

> view of the primary orientation of the Act toward the maintenance of low prices for the consumer, we do not preclude the possibility that a rate increase might be unlawful even though no lower rate could encourage gas production by pipeline companies. On this record, however, if the necessary relationship had been shown we would not consider the rates so high as to be unlawful. 79/

Therefore, even if the Commission had evidence of record before it proper to overturn the Examiner's clear finding that the "parties asking higher rates have failed to supply specific evidence sufficient to meet the standards of the City of Detroit Case", 80/ the Commission's rejection of the thirty years of cost-of-service precedents appears contrary to the basic intent of Congress for such regulation of pipelines as set forth in the Natural Gas Act.

79/ 97 U.S.App. D.C. at 266, 230 F.2d. at 818.

80/ R. 10125.

D. <u>Conversion to Area Rates Will Remove the Incentive for Pipelines to Bargain for Low Rates Resulting in Spiraling of Consumer Costs.</u>

In the broad economic context, it is clear that the extension of area rates to pipelines and their affiliates would have a severe impact on the bargaining position of the pipeline companies for lower cost gas supplies for the benefit of consumers. Pipelines having their own or affiliated production would be discouraged from resisting high area rates paid to producers. The removal of incentives for pipelines to bargain with producers for the lowest attainable rate for a given service will increase the pressure to raise consumer rates beyond what is economically justified. In a group pricing system it is highly desirable that the buyers and sellers are in the position of bargaining just as hard as possible. The extension of area rates, designed for independent producers, to their supposed competitors, the pipeline companies, would stifle rather than encourage competition within the regulatory framework, contrary to the public interest. Such a regulatory policy would encourage rather than discourage the "deficiencies of the market mechanism" pointed out by the Supreme Court in its <u>Permian Basin Area Rate Cases</u> decision:

> The field price of natural gas produced in the Permian Basin has in recent years steadily and significantly increased. These increases are in part the products of a relatively inelastic supply and steeply rising demand; but they are also symptomatic of the deficiencies of the market mechanism in the Permian Basin. Producers' contracts have in the past characteristically included indefinite escalation clauses. These clauses, in combination with

the price leadership of a few large producers, and with the inability or unwillingness of interstate pipelines to bargain vigorously for reduced prices, 63/ have created circumstances in which price increases unconnected with changes in cost may readily be obtained.

63/ The Commission stated that "the entire history of pipeline purchasing activity, since the end of the El Paso monopoly in the Permian Basin, has been characterized by the overriding needs of the pipelines to contract for the large blocks of uncommitted reserves essential to maintain their competitive position in developing markets . . . and their inability to accomplish this objective except at ever increasing prices." 34 FPC, at 182. It is noteworthy that, despite the obvious importance of these proceedings, the pipeline companies did not take an active part here, in the Court of Appeals or before the Commission. See also 2 Joint Appendix 423-432, But see 4 id, at 1384-1388. 81/

The strong position taken by the Court on the necessity for maintaining aggressive competition within the natural gas industry to keep prices down, and the Court's careful distinction between independent and pipeline producers, delineation of the reasons motivating area rate treatment for independent producers, and restriction of the *Permian* decision to the independent producers, hereinafter discussed, compel the conclusion that the *Permian* decision was not intended to be and cannot on an evidentiary basis be employed as a vehicle for extending area rate treatment to producing pipelines and their affiliates.

81/ Permian Basin Area Rate Cases, 390 U.S. 747, 793-94 (1968)

II. THE DECISION OF THE COMMISSION BELOW ALLOWING STRAIGHT AREA RATES FOR PIPELINE AND AFFILIATE PRODUCTION MUST BE REJECTED AS CONTRARY TO LONG STANDING PRECEDENTS GOVERNING TREATMENT OF RATE OF RETURN FOR THE PROTECTION OF CONSUMERS

The Presiding Examiner found that:

> The Staff and the Municipal Group submitted into the record convincing data showing that application of the straight area rates to new gas produced by the pipelines would result in windfalls to the pipeline stockholders coupled with correspondingly higher charges to the consumers. . . . 82/

The Commission rejected both this finding and its Staff's evidence showing that due to different capital structure of the pipeline industry, a 12% rate of return specified for independent producers would result in rates of return to pipeline producers under area rates ranging from 20 to 40% on equity. 83/

The accepted measure of the "profit" of a gas producer, pipeline or independent, is not the "price" he received for his gas, but rather the return on the company's equity investment. 84/

82/ R. 10131, see also R. 10124.

83/ R. 11286; see notes 20,21 *supra*

84/ El Paso Natural Gas Co. v. FPC 281, F. 2d 567, 572 (5th Cir. 1960), *cert. denied*, 366 U.S. 912 (1961); City of Detroit v. FPC, 97 U.S. App. D.C. 260, 263-65, 230 F. 2d 810, 817-819, *cert. denied*, 352 U.S. 829 (1956); Phillips Petroleum Company, 24 FPC 537, 575-76 (1960); and Bluefield Company v. Public Service Commission, 262 U.S. 679 (1923).

This "profit" is also equated with the "incentive" to produce gas. 85/ Numerically, the percentage of overall rate of return permitted to the independent producer differs from that permitted to the pipeline producer. However, in fact, because of the recognized differences in capital structure between the pipeline producer and the independent producer an equal overall return would provide much larger returns on equity ("profit") to the pipeline producer. 86/ Therefore any method of regulation which permits the pipeline producer an overall rate of return equal to that of the independent producer will put the pipeline in a position of super-parity vis-a-vis the independent producers. The following cases illustrate this principle.

In Panhandle Eastern Pipe Line Co. v. FPC 87/ the Commission, based on an analysis of the company's capital structure, determined that to allow a 6% rate of return on the company's production properties would make 12% available to the owners of the common stock on the portion of equity attributable to production assets. In the Permian Basin Area Rate Cases, the Court notes that for pipeline companies

---

85/ Id.

86/ See notes 20-21 supra

87/ 113 U.S. App. D.C. at 96-97, 305 F. 2d 766-67.

(with their relatively thin equity ratios) an overall rate of return of 6 to 6.5% on net investment translates into a yield on equity equivalent to 10 to 12%, but that for independent producers (with their much thicker equity ratios), a higher overall rate of return was required to produce the same return in equity (i.e., profit). Based on this comparison the Court affirmed the Commission's selection of 12% as the proper overall rate of return for gas produced by independent producers. The Court observed that ". . .this return is no more than comparable to that characteristically allowed interstate pipelines." 88/ In El Paso Natural Gas Co. v. FPC, 89/ the financial structure was considered such that a 6.70% rate of return would yield approximately 14.4% on equity capital.

The 12% overall rate of return requested by the Pipeline Production Group (PPG) and other intervenors seeking the adoption of unmodified area rates for pipeline-produced gas would result in at least double the return on equity (i.e. profit) that the independent producers receive and would impose a staggering burden on the nation's gas consumers. Appendix C of the Commission Staff's Brief on Exceptions 90/ illustrates the magnitude of the impact of such a return on the consumer.

88/ 390 U.S. at 806-808.

89/ 281 F.2d at 571.

90/ R. 10452.

The Staff's tabulation shows that applying a pipeline company rate of return of approximately 6 1/2% results in a lowering by over 2.5 cents per thousand cubic feet (Mcf) of the area rate sought by the Pipeline Production Group for company produced gas. Multiplying 2.5 cents times the total pipeline-produced gas in 1965 of 1,237,433,000 Mcf [91/] demonstrates that the Pipeline Production Group's proposal if in effect that year would have cost the consumers of the country $30,935,825 for 1965 alone. Assuming conservatively that new pipeline production for the next twenty-five years is the same as that for 1940-1965, the Pipeline Production Group's proposal to abandon pipeline rate of return would cost consumers a total of $551,233,000. [92/] While the Phase I proceedings in this case relate to future production, it is clear that the Pipeline Production Group's proposal to supersede existing precedents on rate of return alone could ultimately cost the consumers of the country hundreds of millions of dollars, depending on the volume of such production.

91/ For pipeline and on-system affiliates.

92/ Total production of 22,049,322,000 Mcf x 2.5 cents per Mcf; see Ex 21, Sch. 6 (R. 5814) and Ex 6, p. 13 (R. 5750).

Neither the legal authorities [93/] nor this record [94/] supports the Commission's erroneous rejection of the Examiner's conclusion that "the financing of pipeline production operations are in fact markedly cheaper than the financing of such efforts by independent producers, or that pipelines can significantly utilize their debt resources to reduce the cost of production activities. . . ." [95/] The Commission refuses to acknowledge the economic realities of the position of the independent producer vis-a-vis the pipeline producer, namely that because of the difference in capital structure between the pipeline producer and the independent producer, the return on equity

---

93/ This difference and the resulting necessity for differing rate-of-return treatment to the independent producer in contrast to the pipeline producer was acknowledged in the following illustrative cases: Permian Basin Area Rate Cases, 390 U.S. 747, 806-808 (1968); Panhandle Eastern Pipe Line Co. v. FPC, 113 U.S.App. D.C. 94, 305 F.2d. 763, 766-67 (D.C. Cir., 1962); Southern Louisiana Area Rate Proceeding, ¶10,983 CCH Utilities Law Reporter, Federal New Matters 13, 616-617; and in Phillips Petroleum Co., 24 F.P.C. 537, 575-76 (1960).

94/ R. 10108, 10124.
R. 493; R. 621, 629, 630, 631; R. 1085, 1091; R. 1092; 4611; R. 4258; R. 496, 503-4; R. 4257; R. 4425-26; R. 4610; R. 5013 ;

95/ R. 11286

and thus the resulting profit at the same overall rate of return is much higher for pipelines. This results in the anomaly that although the Commission in its opinion No. 568 proclaims "parity" of the independent producers and the pipeline producers, it is in fact placing the pipeline producer in a position of "super-parity" in that the 12% overall rate of return accorded the pipeline will result in an excessive return on equity to the pipelines ranging between 20-40%, to the severe detriment of the consumers. 96/

96/ R 495-96; 44R 4990-91; exhibit 67, Schedule 2. In fact, the Commission's decision below would undoubtedly be cited by the independent producers as grounds for a higher return in the area rate cases, leading to a vicious spiral of upward rates.

III. THE DECISION OF THE COMMISSION BELOW ALLOWING STRAIGHT AREA RATES FOR PIPELINE AND AFFILIATE PRODUCTION MUST BE REJECTED AS CONTRARY TO LONG STANDING PRECEDENTS GOVERNING TREATMENT OF INCOME TAX BENEFITS FOR THE PROTECTION OF CONSUMERS.

The Commission's application of area rates to pipeline production effectively undermines the longstanding, court-sanctioned policy that the consumer should pay only the actual taxes incurred by the pipeline. 97/ The adoption of area rates for pipelines prevents the tax credits emanating from pipeline production from being used to reduce the taxes allowed in cost-of-service of the transmission operation, directly contrary to the holding in El Paso, supra, (n.97) that any actual savings in taxes must be passed to the consuming public. 98/ The Commission, once again, chooses without regard to precedent or to the evidentiary facts of record to disregard

---

97/ El Paso Natural Gas Co. v. FPC, 281 F. 2d 567 (5th Cir. 1960), cert. denied, 366 U.S. 912 (1961).

98/ FPC v. United Gas Pipeline Co., 386 U.S. 237, 244-245 (1967); Midwestern Gas Transmission Co. v. FPC, 388 F. 2d 444 (7th Cir. 1968), cert. denied, 392 U.S. 928 (1968); Alabama-Tennessee Natural Gas Co. v. FPC, 359 F. 2d 318, 331 (5th Cir), cert. denied, 385 U.S. 847 (1966); El Paso Natural Gas Co., supra note at 569-573; Panhandle Eastern Pipe Line Co. v. FPC, 305 F. 2d at 767; Southern Natural Gas Co., 29 F.P.C. 323, 334-35 (1963).

its own prior policies, affirmed by the courts, designed to assure consumer protection from exploitation by the pipeline companies.

The Commission concludes that since it has decided to value pipeline-produced gas at the area rate applicable to independent producers, the strictures of the El Paso case requiring the flowing through of tax benefits are henceforth inapplicable. On the contrary, the holding in El Paso, although necessarily rendered in a cost-of-service proceeding, was not restricted to application in such a case; rather, it was a principle of general application looking to the protection of the consumer interest. Specifically the court held that:

> . . . full effect must be given to the Congressional intent to make the several tax savings available to this taxpayer. . . We think, however, that this does not mean that these tax benefits are to be translated into additional profits for the regulated company over and above a reasonable return on its investment. . .
>
> * * * *
>
> . . . Congressional purpose and intent. . . indicates that [tax benefits are] designed to encourage the exploration for and the development of oil and gas properties. . . .
>
> * * * *
>
> El Paso contends that this policy means that it is entitled to keep the tax benefits thus granted to it as a gas producer over and above an amount charged for its gas that would represent a reasonable return on its investment. We hold that this does not follow. . . The requirement that the Commission determine a just and reasonable rate is not

> modified by reading into the statute an exception to the extent that the prices charged may be sufficient to afford a just and reasonable rate plus an amount representing a savings in taxes granted to the gas industry. . . . .
>
> We think, in short, that there is no statutory authority for the Commission to treat actual savings in taxes to which natural gas companies are entitled any differently than savings in any other cost of service. It is the obligation of all regulated public utilities to operate with all reasonable economies. This applies to tax savings as well as economies of management. The net result of this, of course, is that such savings as are effected are passed on to the consuming public. This we consider to be the natural and necessary consequence of rate regulation. 99/

If El Paso had been permitted to retain these tax benefits it would have received a substantial "additional profit. . . . over and above a reasonable return on its investment." Specifically, the Court noted that in a prior determination the Commission had found that the financial structure of El Paso was such that a 6% rate of return would yield approximately 14.4% on equity capital. The retention of tax benefits would, as estimated by the court, increase this return on equity to approximately 22.1%.[100/]

99/ 281 F. 2d at 571-573.

100/ 281 F. 2d note 5 at 571.

Further if El Paso had been permitted to include the tax savings in its cost of service, although it did not actually pay the taxes 101/ it would have been in violation of the well-established principle that a regulated pipeline company can charge its consumers only for actual taxes paid, taking into account all available deductions and savings on its tax returns. 102/ Again although this principle was necessarily asserted only in cost-of-service proceedings, the unique utility function of the pipeline company requires that it be applied to such company regardless of the method utilized in pricing gas produced by the pipeline. The principle of general application is well stated in City of Lexington, Kentucky v. FPC: 103/ :

> We find nothing in the Natural Gas Act which requires the Commission to ignore the usual principles of cost accounting and set up a fictitious and unreal tax expense on the part of the utility in order to give it the entire benefit of the tax saving statutes and none to the consuming public. The very spirit and purpose of the regulatory provisions of the Natural Gas Act point the other way. 104/

101/ 281 F.2d at 571.

102/ See note 99, sufra

103/ 295 F.2d 109 (4th Cir. 1961).

104/ 295 F.2d at 116.

The impact of the Commission's Opinion No. 568 on the consuming public will be substantial. 105/ Since under it the transmission cost-of-service would include imputed or hypothetical expenses for taxes not in fact paid, the result will be the allowance of a return clearly in excess of the fair rate of return from transmission operations. The consuming public thereby will be saddled with additions to the cost of service on the transmission operation representing increased costs to them not only by the increase in gas price (via area rates) which can be allowed in the cost of service but also by inclusion therein of hypothetical taxes and in addition will be deprived of spillover benefits which would otherwise be utilized to reduce the taxes paid on the transmission function thereby potentially reducing the overall cost of gas to the consumer. Also because the Commission imposes no requirements on the pipelines to plow back their tax credits into their production operations, it is quite possible that these credits would be utilized in a venture bearing no relation to the need for additional gas reserves.

105/ The evidence in this case shows that no less than nine pipeline respondents have such tax spillovers on the basis of a 1962 earning allowance at 6-1/2% rate of return. (Exhibit No. 70, page 2, R. 6162). The five

105/ Continued

largest spillovers shown in Exhibit No. 70 are as follows:

Colorado Interstate Gas Co.	$2,159,867
Panhandle Eastern Pipe Line Co.	1,959,785
Natural Gas Pipeline Company of America	1,540,544
Southern Natural Gas Co.	1,351,279
Hope Natural Gas Co.	1,285,110

It is axiomatic that the tax loss spillovers would tend to increase if increased drilling activities were undertaken by any of the pipeline companies whose production department was in a tax loss position. It also follows that an increase in drilling activity could move all thirteen of the pipeline respondents listed in Exhibit No. 70 into a production department tax loss position. Data concerning the benefits which consumers enjoy from the spillover of tax losses associated with affiliate production are not shown in the record. The Commission determined, however, that Union Producing Company had a tax loss for the period 1957 to 1961, inclusive, which resulted in a reduction of taxes for the consolidated group consisting of Union, its affiliate, United Gas Pipeline Company, and others. The effect of Union's and other affiliates' loss spillover was determined to be a reduction in United Gas Pipe Line Company's effective tax rate for the 1957-1961 period from 52 to 50.04 per cent. This effective rate was used to compute the tax allowance in United's cost of service and thus Union's tax loss was treated by the Commission as a benefit to gas consumers. <u>United Gas Pipe Line Company</u>, 31 F.P.C. 1180, 1190-91, 1209-10 (1964). The U.S. Supreme Court upheld the Commission's action in this regard. <u>FPC v. United Gas Pipe Line Co.</u>, 386 U.S. 237, 244-45 (1967).

IV. THE COMMISSION'S CONVERSION OF THIS PROCEEDING FROM ADJUDICATORY TO RULE-MAKING DEPRIVES THE PETITIONERS OF DUE PROCESS.

A. This proceeding was intended to be adjudicatory.

The Commission in Opinion No. 568 improperly treats the proceedings in this case as in the nature of a rule-making proceeding rather than an adjucication controlled by the record-hearing provisions of the Administrative Procedure Act. 106/ From its inception as part of the Hugoton-Anadarko Area Rate Proceeding, 107/ this proceeding has been established as an "Area Rate Proceeding", treated as an adjudication on the record in a manner similar to the Area Rate Cases. 108/ In each of these cases a full hearing was required to establish a record upon which to fix proper rates. The instant case is the only instance in which the Commission ventured outside the record to reach a decision clearly not warranted by the record evidence.

On June 29, 1964, the Commission enlarged the Hugoton-Anadarko Area Rate Proceedings, which was originally initiated

---

106/ 5 U.S.C. § § 556-57

107/ 31 F.P.C. 1595 (1964)

108/ E.g., Permian (AR61-1); Southern Louisiana (AR61-2); Hugoton-Anadarko (AR64-1); Texas Gulf Coast (AR64-2); and Other Southwest Area (AR 67-1).

to determine just and reasonable rates in that area with respect to the production of gas by independent producers and pipeline affiliated producers, to include pipeline-producing companies. The area rate format established for the gathering of information relating to pipeline-produced gas demonstrates that an adjudicatory procedure was contemplated:

> . . . We do not, of course, prejudge any of these issues; the Commission has not arrived at a new policy, even tentatively; rather we invite a thorough development of the facts and ventilation of the issues on this record so that we may better formulate policy in the future. 109/

The severance of the proceeding in 1966 to be established as a "Pipeline Production Area Rate Proceeding" (Docket No. RP66-24) in no way altered the adjudicatory nature of the proceeding. The Commission's order on June 16, 1966 110/ made it clear that RP66-24 was not to be a rule-making proceeding:

> . . . the present Commission . . . has not yet determined the extent to which the emerging area price techniques, which it intends to apply to independent producers, should also be applied to the production activities of natural gas pipelines . . . the present Commission adheres to the position . . . that it is legally free to depart from cost-of-service concepts in pricing a pipeline's gas production to the extent that a record presents an adequate basis for moving to a more appropriate pricing basis. 111/

109/ 31 F.P.C. 1595 (1964) (Emphasis added).

110/ 35 F.P.C. 1033 (1966).

111/ 35 F.P.C. at 1034 (Emphasis in original).

B. The Examiner treated the proceeding as adjudicatory and reached his decision based on the record compiled in this case in conformity with the hearing provisions of the APA.

Examiner Lande, the Presiding Examiner in the subject proceeding, interpreted the format established by the Commission for resolution of the question of the pricing to be accorded pipeline-produced gas as adjudicatory. He treated that mandate as establishing the Commission's position that:

> the 'factual context' of an area rate proceeding would be 'particularly useful for evaluating the various problems presented by any shift to area rate method of treating pipeline production.'112/

And with respect to the severance, he observed that:

> . . . the Commission subsequently determined that, given the factual presentation necessary to put the economic and legal policy involved into context, the issues involving the proper costing method to be applied to pipeline produced gas should be examined in a separate proceeding. 113/

In execution of this mandate, Examiner Lande received extensive evidence on all the designated issues. From the record thus compiled (totalling in excess of five thousand pages), he made detailed findings of fact leading to the conclusion that the proponents of area rates for pipeline production had failed to

---

112/ R. 10063.

113/ R. 10063.

justify a significant change from the established cost-of-service method of regulation. The Examiner reached the following pivotal conclusions:

1. Re continuation of cost of service.

> . . . Heretofore the cost-of-service metho d regulation, which the Commission has been applying to the pipeline produced gas, maintained a healthy competitive atmosphere, under which individual pipelines prospered; where circumstances truly warranted it the pipelines produced adequate supplies of their own gas.114/
>
> . . . a gas rate increase must not be brought about prematurely. The record herein contains evidence to warrant only an interim balancing of equities, rate changes of only minor proportions. The Staff witnesses have effectively demonstrated that for the time being pipelines are still in a favorable money raising position and are also likely to secure tax benefits from production which would produce a windfall to the producers at the expense of the gas ratepayers. . . . 115/
>
> The parties asking higher rates have failed to supply specific evidence sufficient to meet the standards of the City of Detroit case. . . "that the rate increase is in fact needed and is no more than is needed for the purpose. . . ."116/

2. Re incentive for exploration and development; gas supply shortage.

> . . . The problem is not whether pipeline production should be encouraged, but how much should it be encouraged, so that it will best benefit the pipelines, but not place an

---

114/ R. 10130.

115/ R. 10124.

116/ R. 10125.

> unnecessary added burden on the consumers. 117/ . . . This is a matter upon which the Pipeline Group advanced considerable contentions, but insufficient evidence. 118/

In response to the Pipeline Group's contentions that there is a present and growing need for pipeline production to meet the sharply increased demand for natural gas and that area rates will stimulate exploration, 119/ the Examiner found that:

> Since there has been <u>no direct evidence demonstrating either the need for additional supply or, the necessary amount of such incentive</u>, such additional allowance cannot be allowed. 120/

3. <u>Re comparability of pipeline companies for group pricing</u>.

> Since the only data in the record shows that pipelines, as a group and individually, do not have costs comparable to those national costs used in the independent producer area rate proceeding, and are otherwise not properly comparable in their activities, it is not proper to fully apply independent producer area rates to such pipelines . . . . The deviation from average cost for pipelines is much greater than for independents. . . . the pipelines are already being regulated under an effective method of regulation which gives recognition to the individual cost peculiarities. . . . 121/

117/ R. 10126.

118/ R. 10125.

119/ R. 10070-71, 10072-83.

120/ R. 10083. <u>See also</u> R. 3120.

121/ R. 10080.

4. Re impact of straight area rates on the pipeline companies.

There are wide disparities in pipeline production costs with respect to their gas leases. If it were decided to make it optional whether pipelines should go on area rates or remain on cost-of-service pricing with respect to "new gas," those who can obtain "cheap new gas" will promptly do so--those who must obtain "expensive new gas" will not. This would hurt the consumers both ways. If pipelines are put on a compulsory area rate for the future, some will reap windfalls. Others might experience substantial losses. . . Furthermore, producer losses may affect the individual producer's ability and willingness to engage in subsequent exploration and development--a private activity, whereas pipeline losses could affect their ability to perform their basic transportation functions--a public duty. 122/

5. Re impact of straight area rates on consumers.

. . . a straight area rate for pipeline produced gas is likely to be more profitable than the same straight area rate for independent producers; it would also tend to unduly increase the cost of gas to their customers, and it would not benefit the public at large. While pipelines can produce new gas for about the same cost as the independent producers, they fail to rebut effectively the contentions of the Staff and the Municipal Group, that area rates would yield pipelines excessive profits and at the same time would eventually tend to unduly raise the cost of gas to the public. The Commission must secure for the customers the lowest just and fair gas rates consistent with adequate service. . . . 123/

122/ R. 10128.

123/ R. 10129.

C. <u>The Commission's reliance on untested extra-record material to support its opinion is contrary to all notions of adjudicatory procedure and due process.</u>

The Commission relies on two key facts to support its determination that "new" pipeline-produced gas must be priced in accordance with area rates: 124/

> <u>Key Fact #1</u>--a critical gas shortage impels a switch in the method of pricing pipeline-produced gas. 125/
>
> <u>Key Fact #2</u>--area rate pricing will provide incentive for exploration and development sufficient to remedy the gas supply shortage. 126/

Neither of these facts is supported by the record in this proceeding. 127/

The first key fact is based upon industry-oriented statistics, specifically the American Gas Association (AGA) Committee Report of April 17, 1969, concededly not in the record. 128/ This report was issued more than two months prior to the oral argument in this proceeding, June 27, 1969, but no action was taken to introduce these industry statistics into the record subject to cross-examination. The AGA figures are internally inconsistent and reflect unexplained

---

124/ The issue of the treatment of "old" pipeline produced gas has been set down to be heard as Phase #7 Docket No. RP66-24.

125/ R. 11281, 11284.

126/ R. 11281; 11283-84; 11287; 11290.

127/ R. 10125-26.

128/ R. 11281, 11284.

manipulations of data. Neither the Commission nor any party to this case has ever had the opportunity to review the data used in the AGA figures, much less to test it on cross-examination. 129/

129/ The FPC "Staff Report on National Gas Supply and Demand" issued on October 1, 1969, at page 2 contains the following illuminating statements regarding the AGA statistics.

> "Much of the factual base for this report is industry supplied data, including particularly the American Gas Association (AGA) proven reserve estimates and production information. The gas supply statistics of the American Gas Association are compiled from the confidential records of individual independent producers and pipeline companies. Neither the confidential reserve data of these companies nor the exact method by which this data is summarized for the American Gas Association reports have ever been divulged to the Federal Power Commission. For purposes of this report we have accepted at face value all industry-furnished supply data. Our conclusions must therefore be weighed against the assumed accuracy of our data base."

See relating to the doubtful accuracy and the potential for manipulation inherent in the AGA statistics the Address by Lee C. White, former Chairman, FPC, A Regulator Looks at the Electric and Gas Industries With a Sidelong Glance at Investment Analysts, Before the Financial Analysts Federation 5, May 16, 1969: Commissioner White observed that:

> Unlike FPC's authority to acquire data from the electric utility industry, we are severely limited in our ability to obtain the basic information so essential to a proper analysis of the natural gas industry. As I see

129/ continued.

> it, this situation is intolerable and must be corrected. The industry cannot have it both ways--it cannot reasonably claim a gas shortage exists and at the same time continue to refuse to make the basic data available.

For an excellent discussion of the potentiality for and actual past manipulation of AGA statistics see Bertram D. Mill, "Is a Gas Shortage in Prospect", Public Utilities Fortnightly 30 (October 14, 1965).

There has been no valid proof of any sort of the asserted "gas shortage" upon which the Commission relies. With respect to the pipeline production group's contention that there is a growing gas supply shortage, Examiner Lande observed that there "has been no direct evidence demonstrating . . . the need for additional supply." 130/ In the absence of proof and opportunity for cross-examination and rebuttal, the blind acceptance by the Commission of the extra-record, self-serving industry statements deprives the consumers of the protection accorded them by the terms of the Natural Gas Act. 131/ It should be noted that the facts regarding the present gas supply situation in the United States are currently being investigated in an adversary context in Docket No. AR69-1.

A striking parallel which demonstrates the dubious relevance of the industry-oriented statistics can be drawn between the producers contentions in this case and those advanced whenever the industry urges the adoption of a gas pricing method which will substantially raise prices. The standard assertion is that the incentive for exploration and development is inadequate since the ratio of gas reserves

130/ R. 10083.

131/ Section 15 of the Natural Gas Act, 15 U.S.C. s 717n (1964)

See Midwestern Gas Transmission Co. v. FPC, 103 U.S.App.D.C. 360, 258 F. 2d 660 (D.C. Cir. p958), vacated and remanded per curiam for dismissal 358 U.S. 380 (1959); Berliner v. District of Columbia, 103 U.S.App. D.C. 351, 258 F. 2d 651 (D.C. Cir. 1958), cert. denied, 357 U.S. 937; Superior Oil Co. v. FPC, 322 F. 2d 601 (9th Cir. 1963), cert. denied, 377 U.S. 922.

to production (R/P ratio) is declining. The concerned producer then asserts that if the consumer will, in effect, pay what the traffic will bear, the producer will be able to expand its exploration and development program. This industry tactic succeeded at the Commission level in the 1954 Panhandle Eastern Pipe Line Company case, in which resort to a fair field price for pipeline-produced gas was permitted in order to allegedly "spur" exploration and development,[132/] but was effectively thwarted by this Court in the City of Detroit Case which reversed the Commission's decision.[133/]

Significantly, in its landmark 1965 Permian Basin Opinion (No. 468), the Commission rejected the relevance of the R/P ratio as anything but a rough indicator of the gas supply situation and also dispelled the notion that higher prices alone would improve the exploration and development picture.[134/] In that case independent producers contended, based on statistics provided by the AGA and the American Petroleum Institute, that the gas supply situation was so critical that if the area price ceiling were fixed below

---

132/ 13 F.P.C. 53 (1954).

133/ City of Detroit, Michigan v. FPC, 97 U.S. App. D.C. 260, 230 F. 2d 810 (D.C. Cir. 1955), cert. denied, 352 U.S. 829 (1956).

134/ 34 F.P.C. 159, 184 (1965).

existing contract price levels, producer exploration and development would be dampened. The Commission found that:

> . . . there is no reason to assume that there is a direct relationship between any calculated R/P ratio and the price of gas. On the contrary, the R/P ratio went steadily down during the periods in which gas prices were staging their most spectacular increases. It seems clear that even an exploratory program which will continue to add substantially more reserves annually than are produced is almost certain to fall short of preventing a further decline in R/P ratios.
>
> As long ago as 1957, the AGA in Gas Facts, 1957 edition, page 6, stated that the industry should not be preoccupied with a 'hypothetical' reserves to production ratio, but should focus its concern on finding sufficient gas to replace that consumed each year. There is considerable doubt that it is desirable, from the point of view of the public or the industry, to require or encourage a high level of proven reserves many years in advance of their probable use. It is an extremely costly matter to find and hold reserves beyond those which are needed to assure ample supplies to consumers . . . .
>
> There is also serious question as to the reliance to be placed on the available R/P ratio figures. . . .135/

The Supreme Court in affirming the Commission's Permian decision specifically supported the Commission's findings on the inconclusiveness of the reserve/production ratio:

> The producers' argument has been uniformly premised upon the assertion that the ratio of proved recoverable reserves to current production is an

---

135/ 34 F. P. C. at 184.

> <u>accurate index of the industry's financial requirements.</u> The producers urge that this ratio has dangerously declined, and conclude that any reduction of prevailing field prices will jeopardize essential programs of exploration. There is, however, substantial evidence that additions to reserves have not been unsatisfactorily low, and that recent variations in the ratio of reserves to production are of quite limited significance. Nothing in the record establishes as proper or even minimal any particular ratio . . .
>
> * * *
>
> . . .the Commission here permissibly discounted the producers' reliance upon this relationship to establish the inadequacy of its rate structure. 136/

This industry tactic has been aptly characterized by one commentator as follows:

> The use of the R/P ratio as proof that the consuming public is nevertheless going to suffer shortages in the near future is simply propaganda. The fact is that distribution companies and the F.P.C. see through this flimsy support for higher prices. This is no more evidence of blindness than the R/P ratio is of impending disaster. 137/

A comparison of the course of conduct followed by the Commission in these proceedings with the standard of conduct on reversing an examiner's decision set by this Court in <u>Cinderella Career and Finishing Schools, Inc.</u> v. <u>FTC</u> issued

---

136/ Permian Basin Area Rate Cases, 390 US 747, 817 (1968).

137/ Bertram D. Mill, "Is a Gas Shortage in Prospect", Public Utilities Fortnightly 31 (October 14, 1965).

on March 20, 1970 138/ makes apparent that the Commission's conduct herein may not be upheld. This Court held that the full Commission reviewing an initial decision may not consider the subject matter de novo disregarding entirely the evidence adduced at a lengthy hearing, and arrive at independent findings of fact and conclusions of law. The Court concluded that the standard applicable to the federal court applies in this instance to the Commission and that the Commission cannot "ignore the findings of fact and conclusions of law . . . substituting . . . [its] judgment . . . on a cold record for that of a finder of fact below."

138/ 38 Law Week 1149 (March 31, 1970). Cf.Texaco, Inc. v. FTC, 118 U.S. App. D. C. 366, 336 F. 2d 754 (D.C. Cir., 1964).

CONCLUSION

WHEREFORE, for the above reasons, the Municipal Gas Group requests the Court to set aside the Commission's Opinions No. 568 and 568-A as contrary to law and the record in this proceeding.

Respectfully submitted,

Richard L. Curry
Corporation Counsel
Mathias M. Mattern
Assistant Corporation Counsel
for Public Utilities
Bernard Rane
121 North LaSalle Street
Chicago, Illinois 60602

Max P. Zall
City Attorney
City and County of Denver
City and County Building
Denver, Colorado 80202

Charles F. Wheatley, Jr.

Charles F. Wheatley, Jr.
William T. Miller
Grace Powers Monaco
2600 Virginia Avenue, N. W.
Washington, D. C. 20037

Attorneys for Petitioners

Of Counsel:
George E. Morrow
Union Planters National
Bank Building
Memphis, Tennessee
38103

Reuben Goldberg
1250 Conn. Ave., N.W.
Washington, D.C. 20036

April 6, 1970

BRIEF FOR RESPONDENT
FEDERAL POWER COMMISSION

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

NO. 23740

City of Chicago, Illinois, et al.,
Petitioners,

v.

Federal Power Commission,
Respondent,

Pipeline Production Group; Mid Louisiana Gas Company; Tennessee Gas Pipeline Company a Division of Tenneco Inc.; Consolidated Gas Supply Corporation, Pennsylvania Gas Company, United Natural Gas Company; Pennzoil Producing Company; Tenneco Oil Company;
Intervenors

ON PETITION TO REVIEW AN ORDER OF THE FEDERAL POWER COMMISSION

BRIEF FOR THE FEDERAL POWER COMMISSION

GORDON GOOCH,
General Counsel,

PETER H. SCHIFF,
Solicitor,

ABRAHAM R. SPALTER,
Assistant General Counsel,

JOSEPH J. KLOVEKORN,
Attorney,
For Respondent,

FEDERAL POWER COMMISSION,
WASHINGTON, D.C. 20426.

June 15, 1970

INDEX

TABLE OF CITATIONS

---

* Cases or authorities chiefly relied upon are marked by asterisks.

Cases continued: Page

Statutes and Regulations:

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

City of Chicago, Illinois, et al.,
Petitioners,

v.

Federal Power Commission,
Respondent,

Pipeline Production Group; Mid Louisiana Gas Company; Tennessee Gas Pipeline Company, a Division of Tenneco Inc.; Consolidated Gas Supply Corporation, Pennsylvania Gas Company, United Natural Gas Company; Pennzoil Producing Company; Tenneco Oil Company;
Interveners

On Petition to Review an Order
of the Federal Power Commission

BRIEF FOR THE FEDERAL POWER COMMISSION

REFERENCES TO RULINGS

The Commission's Opinion 568 (R. 11270-11294), here under review, was issued October 7, 1969, and will soon be reported at 42 FPC 738. The Commission's Opinion 568-A (R. 11358-11364), modifying its original order and denying rehearing was issued December 5, 1969.

COUNTERSTATEMENT OF ISSUES PRESENTED

1. Whether the Commission's order establishing as a matter of policy that, in future pipeline rate proceedings, gas produced by pipelines or their affiliates from leases acquired after the date of the order would be included in the pipeline cost of serv-

ice for ratemaking purposes at the applicable just and reasonable area rate, was rationally based and supported by substantial evidence.

2. Whether the Commission was foreclosed from applying the principle of area rates approved by the Supreme Court in the Permian Basin Area Rate Cases, 390 U.S. 747 (1968), to all producers, including pipelines with respect to their production from future acquired leases.

This case has not previously been before the Court.

COUNTERSTATEMENT OF THE CASE

Petitioners challenge the Federal Power Commission's policy decision, issued October 7, 1969 (Opinion 568, R. 11270-11294), determining that in future pipeline rate proceedings gas used by pipelines from their own production or of their affiliates from leases acquired after the date of the order would be priced for ratemaking purposes at the just and reasonable area rate established for independent producers 1/ (R. 11292-11293). This policy is designed to protect consumers from excessive charges for natural gas produced by pipelines while utilizing area pricing to encourage pipelines, who have a particular interest in

---

1/ The Commission made certain exceptions to this rule. If a pipeline or affiliate acquired, after the effective date of this order, a developed or undeveloped lease, either directly or through an intermediary, from another pipeline or affiliate which acquired the lease prior to the effective date, the lease would be subject to cost of service treatment. The applicable price of gas from any other developed lease acquired from which jurisdictional sales were being made was to be the lower of the contract price or the applicable area price. Where non-jurisdictional sales were being made from leases, the applicable rate would be the just and reasonable area price (R. 11363).

the adequacy of gas supply, to increase their search for needed gas supplies.

Background.--While the vast bulk of natural gas in the United States has always been produced by independent producers, 2/ the Commission exercised no jurisdiction over the sales of independent producers until the Supreme Court's 1954 decision in Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672. The Commission did, however, regulate the gas production of interstate pipeline companies in the course of regulating the rates of such pipelines since the beginning of regulation under the Natural Gas Act, 3/ by including the portion of the company's production costs allocable to the gas sold by the pipeline as part of the pipeline's overall cost of service. See, e.g., F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944); Panhandle Eastern Pipe Line Co. v. F.P.C., 324 U.S. 635 (1945); Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581 (1945). The Commission has generally

---

2/ "Independent producers are those that do 'not engage in the interstate transmission of gas from the producing fields to consumer markets and [are] not affiliated with any interstate natural-gas pipeline company.'" Permian Basin Area Rate Cases, 390 U.S. 747, 756, n. 6 (1968).

Pipeline gas producers and affiliated companies accounted for approximately 13.5 percent of the gas entering into the lines of interstate pipelines in 1962 (R. 11281). The remainder comes from independent producers.

3/ The Natural Gas Act, 15 U.S.C. 717(a), et seq., was enacted in 1938.

followed this individual company cost-of-service approach for valuing a pipeline's own production. 4/

After the Supreme Court's decision in Phillips, supra, determining that the Commission had jurisdiction over the sales in interstate commerce of natural gas by independent producers, the Commission also attempted to regulate these producers on an individual company cost-of-service basis. In 1960, however, the Commission, after consideration of an extensive record in the first fully tried independent producer rate case to come before it, concluded that such an approach was neither economically sensible nor administratively feasible with respect to independent producers and that it appeared probable that rates for producers could more reasonably be determined on an area or industry basis. See Phillips Petroleum Co., 24 FPC 537 (1960), affirmed sub nom. Wisconsin v. F.P.C., 112 AppDC 367, 303 F. 2d 380 (1961), affirmed, 373 U.S. 294 (1963). In 1965, the Commission, in its first area rate case, finally determined on the basis of an extensive record that the area rate approach was indeed a more meaningful basis for regulating the rates of independent producers. See Permian Basin Area Rate Proceeding, 34 FPC 159 (1965), affirmed, 390 U.S. 747 (1968).

The present proceeding.--On June 29, 1964, the Commission ordered the enlargement of the issues in the then pending Hugoton-

---

4/ Just prior to Phillips, supra, the Commission sought to depart from reliance on costs for pipelines. It was reversed on review by this Court. City of Detroit v. F.P.C., 97 AppDC 260, 230 F. 2d 810 (1955), certiorari denied, 352 U.S. 829 (1956). See also, Mississippi River Fuel Corp. v. F.P.C., 102 AppDC 238, 252 F. 2d 619, certiorari denied, 355 U.S. 904 (1957).

Anadarko Area Rate Proceeding to consider whether adoption of the area rate approach for independent producers would warrant any changes in the regulatory treatment of pipeline produced gas. 31 FPC 1595. On April 13, 1966, the Commission ordered the severance of this issue from the Hugoton-Anadarko proceedings and directed that initially the severed proceeding should consider only the production from leases acquired after the date of determination of the issue (R. 7110-7118). The Commission decision in that portion of the proceeding, referred to as Phase I, is now before the Court. All pipeline companies engaged in the production of natural gas in more than an incidental capacity were made respondents in the proceeding (R. 7117). Numerous other parties, including States or their commissions, county and municipal bodies, natural gas distributors and producing companies, were permitted to intervene (R. 7510-7514).

During the lengthy proceedings which followed, 5/ four basic positions developed. The use of the same area rates for pipelines as for independent producers was advocated by a group of pipeline producers (Pipeline Group). 6/ Consolidated Gas

---

5/ "Factual and policy presentations were made by 35 witnesses. Pertinent data developed in area rate cases was included as items by reference. There were 5,439 pages of testimony, 73 exhibits, and 36 days of cross-examination of direct and rebuttal testimony." (R. 10063).

6/ Fourteen pipeline producers comprise this group. These pipelines were: Cities Service Gas Company, Colorado Interstate Gas Company, Humble Gas Transmission Corporation, Kansas-Nebraska Natural Gas Company, Lone Star Gas Company, Natural Gas Pipeline Company, Northern Natural Gas Company, Panhandle Eastern Pipeline Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, Trunkline Company, United Fuel Gas Company and United Gas Pipeline Company (R. 10061).

Supply Corporation argued that although the area rate method was appropriate for most producers, whether pipeline or independent, a unique situation in Appalachia, where most of its activities are located, made continuation of individual company cost of service desirable there for pipelines. The Commission staff, supported by the California Public Utilities Commission, also favored extension of the area rate method to all producers, except those in Appalachia, with certain modifications in the rate of return component of the applicable rate and in the treatment of possible income tax benefits arising from future exploration and development. A group of municipalities and municipal gas distributors (Municipal Group), 7/ on the other hand, argued that individual company cost-of-service regulation should be continued. El Paso Natural Gas Company concurred in this position.

Examiner's initial decision.--On March 3, 1969, the examiner issued his initial decision (R. 10045-10168). While holding that the present cost-of-service regulation for pipeline production and area rate regulation for gas produced by independent producers caused a disequilibrium in rates for future reserves and that it would be "very difficult to maintain the rigid cost-of-service regulation indefinitely" (R. 10124), the examiner stated that a complete adoption of area rates at this time would be premature (R. 10124-10125). The examiner believed adoption of area rates would result in a rate increase to the consumer and that on the record there was insufficient specific evidence

7/ The Municipal Group was composed of the American Public Gas Association, City of Chicago, City and County of Denver, and Memphis Light, Gas and Water Division (R. 10057).

to meet what he believed to be the standards established by this Court in City of Detroit v. F.P.C., 97 AppDC 260, 230 F. 2d 810 (1956), certiorari denied, 352 U.S. 829 (1957), "that the rate increase is in fact needed and is no more than is needed, for the purpose" of encouraging new gas production (R. 10125). The examiner found, however, that historical costing methods which rolled in new and old production expenses distorted "the almost certain fact" that pipeline produced new gas for all companies is about as costly as the average independent producer cost (R. 10127). The examiner proposed a compromise of continuing the cost-of-service method for producing pipelines but allowing them to retain part of any tax deduction benefits from the production of new gas. The examiner also would have allowed pipeline affiliates to charge the area rate for ten percent of their new gas production sold on-system and the full area rate for new production sold off-system (R. 10132).

Commission's opinion.--After consideration of the exceptions to the initial decision and oral argument, the Commission issued Opinion 568 on October 7, 1969 (R. 11270-11294). It rejected the examiner's compromise solution, finding that application of area rates to the production of gas by pipelines and their affiliates from future acquired leases would best serve the public interest, both because the area approach would assure lower reasonable rates for consumers and not saddle consumers with high cost production resulting under recent cost-of-service experience and also because the built-in incentives in area pricing could reasonably be expected to lead to greater pipeline participation in the needed search for new gas reserves. The Commission also

concluded that there was no basis for modifying the producer area rates by using a different return for each pipeline and by not permitting the pipelines to utilize income tax benefits resulting from production activities to the same extent as independent producers. In reaching its decision, the Commission agreed with the examiner that although historically pipeline costs of operation showed a greater spread from the mean average than in the case of independent producers, this was merely indicative of the different circumstances in which the pipelines originally undertook their production operations (R. 11285, 10127). But, contrary to the examiner, it concluded that these historically-based differences gave no indication that the costs of production by different pipelines from future-acquired leases were likely to diverge significantly over time under the area rate approach.

On December 5, 1969, the Commission issued Opinion 568-A (R. 11357-11364), denying the applications for rehearing filed by the Municipal Group, the State of California and the Public Utilities Commission of California, and by El Paso. In response to the Municipal Group's application, it modified its original opinion to make clear its intention that leases acquired, either directly or through intermediaries, from other pipelines or their affiliates which had held them prior to the date of the opinion would be treated under the conventional individual company cost-of-service treatment.

This petition for review followed.

ARGUMENT

I. THE COMMISSION REASONABLY CONCLUDED THAT THE USE OF AREA RATES TO COST GAS PRODUCED BY PIPELINES FROM SUBSEQUENTLY ACQUIRED LEASES WOULD BEST SERVE THE PUBLIC INTEREST

The thrust of petitioners' argument (Pet. Br. pp. 15-44) is that since pipeline production has been regulated in the past by the individual company cost-of-service method with repeated court approval, no change should be made. But, as the Commission stated (R. 11282), the legality of the existing system of valuing pipeline production by no means shows it is the most appropriate approach for future acquired leases. To the contrary, the Commission, relying on its recently acquired experience in producer area rate proceedings and the record here, reasonably concluded that it was preferable to cost pipeline production from subsequently acquired leases on an area basis because this was likely to have the desirable effect of encouraging increased searching activity for gas by pipelines without increasing the overall cost of gas to the consuming public.

It is true, of course, that since as far back as 1942 the Commission had, with judicial sanction, determined the cost of pipeline-owned production, like other components of a pipeline's jurisdictional operations, on an individual company cost-of-service basis (R. 11281). At the same time it should be recognized that until 1954 the Commission did not regulate independent producers who supplied the vast bulk of the gas entering

interstate pipelines. Thereafter, until 1960, the Commission attempted to regulate independent producers on an individual company cost-of-service basis but concluded in Phillips Petroleum Co., 24 FPC 537 (1960), affirmed sub nom. Wisconsin v. F.P.C., 112 AppDC 369, 303 F. 2d 380 (1961), affirmed, 373 U.S. 294 (1963), that regulation of such producers should be attempted on an area basis. In 1964, prior to any area rate decisions, the present proceeding was initiated to determine if pipeline production should continue to be costed on an individual company basis or if an area approach of some type might be more desirable.

In 1965, the Commission issued its first area rate decision in the Permian Basin Area Rate Proceeding, 34 FPC 159 (1965), affirmed, 390 U.S. 747 (1968). Taking into account extensive evidence on the economics of gas production (34 FPC at 178-179, 311-337), the Commission in that case finally concluded that gas sold by independent producers should be priced on an area approach. Its conclusion here (R. 11282) that the basic reasons for pricing the gas of independent producers on the basis of composite costs are also applicable to costing pipeline production from leases acquired after the date of its decision is fully warranted, as an analysis of Permian and the record here demonstrates.

A. The Area Rate Principles Underlying Permian Were Properly Found to Be Applicable to Pipeline Production from Future Acquired Leases

Although petitioners suggest (Br. p. 35) that the area rate approach in Permian was adopted primarily for administra-

tive convenience factors applicable peculiarly to independent producers, an examination of Permian makes it clear that the approach was basically selected because it appeared to be much better adapted to the economics of gas production than individual company cost of service, while also providing a practical administrative means of controlling prices. In Permian, the Commission explained that "[b]asic to this determination [to use the area approach] is the fact that objective cost standards for fixing just and reasonable rates for producer sales can best be developed by examining overall producer experience" 34 FPC at 179.

While the Commission concluded that industry or area costs of gas-well gas should be used as a yardstick for just and reasonable rates, a cost yardstick can be appropriate only if there is a reasonably reliable relationship between cost incurrence and results obtained. Companies engaged in gas exploration do not experience such a predicable relationship on each exploratory prospect. A given prospect may be a dry hole or a marginal well or it may turn out to be commercially productive or even a bonanza. Moreover, because properties, activities and, of course, luck, vary among producers, and vary for a given producer over time, substantial variance in cost experiences may be expected among producers at any one point or year in time. Thus, it became clear in Permian that the cost of any one producer at a particular point in time does not (except by chance) describe the average, typical or reasonable cost prospects for any producer--even himself, since there is

no reason to assume that a producer will have the same costs in the next or in succeeding years. But it was also shown that a producer's costs tend to average out over the years and that, on an industry or area basis, a substantial degree of stability in costs exists from year to year. See, e.g., 34 FPC at 179, 350-351.

As the Commission explained in Permian, these factors showed the fairness of establishing uniform area rates based on average costs. Under that method, the average producer will recover his costs over the long run; his good years will balance his bad; his costs will tend to approximate the group's experience. Some producers, to be sure, may do better than the average and so earn more on their investment than the return used in determining the area rate. The producer who finds large reserves will be able to achieve greater profits than a producer whose exploration results in dry holes or marginal wells; the producer who operates efficiently and with economy will make more money than the producer who manages his business poorly. As the Commission said in Permian (34 FPC at 179), area pricing thus provides a strong incentive to prudence, economy and skill which the individual company cost-plus pricing would not provide in an industry like gas production where individual cost norms are impossible to fix.

Moreover, because area pricing conformed to the characteristics of the industry, which is one where there is scope for greater or lesser reward as dictated by the results of exploratory effort, it was viewed as providing producers the incentive

needed to explore for the nation's increasing demand for natural gas while affording consumers the protection which the Act intended. This incentive factor became particularly significant because it was demonstrated in Permian, 34 FPC at 185-186, 325-333, for the first time that the production industry had since around 1960 realized that it has the capability of directing its exploratory efforts toward finding gas reservoirs; no longer need gas discovery be only a by-product of the search for oil as it had been in the past.

This was important because so long as gas was found as a by-product of the search for oil, the gas price could have little effect on supply of gas because of the much larger total revenues received for oil than for gas. But once it was realized that gas could be searched for separately, the price can be used as a supply eliciting tool, provided it is sufficient to cover the current cost of finding and producing gas-well gas, including an appropriate return. This meant, of course, that if the price for such gas were fixed on the basis of the average of current and historical costs, a price so determined would not provide the incentive to look for new gas-well gas if the current cost exceeded that average.

It was for this reason that the Commission adopted the two-price system, fixing the new gas price on the basis of the most recently available national data, while fixing the price for other gas on the basis of historical average costs. The new gas-well gas price was intended to provide an incentive to explore for the gas supplies needed by the consumer. As

the Commission explained (Permian, 34 FPC at 186), this incentive was one built into the pricing system by relating the new gas price to current and future costs, not by adding any sum earmarked for that purpose. Since, as we have seen, the costs of any particular producer for a most recent year would only by sheer coincidence give any indication as to his cost expectations for the future, the need to use current composite industry costs was particularly important in developing the new gas price.

While the Commission's Permian decision dealt in terms only with the regulation of independent producers, the Commission was plainly on sound ground when it concluded here that the same problems which made individual cost of service an inadequate measure of the costs of exploration and development of gas reserves for independent producers existed in attempting to measure these same costs for pipeline producers from future acquired leases (R. 11282). Thus, the record shows that the production costs of individual pipelines are erratic from year to year just as are those of independent producers (R. 5871-5881). 8/ Indeed, there is no basis for assuming that the results of an individual pipeline's searching efforts would have any closer correlation on a short-range basis to the amount invested than would those of independent producers.

8/ For example, the record indicated that one pipeline producer's cost of exploration and development per Mcf of gas produced in 1956 was 13.3¢; in 1957, it was 20.7¢; in 1958 and 1959 these costs were 14.6¢; in 1960, it was 6.7¢; in 1961, it was 8.6¢; and in 1962, it was 13.3¢ (R. 5882).

On the other hand, as both the Commission and examiner found (R. 11285, 11361-11362, 10127), 9/ the record indicates that the costs involved in the production of new gas by pipelines would approximate the industrywide average cost of new gas established for independent producers. Various expert witnesses, including staff's, testified that on the basis of available data and the similarity of production operations whether conducted by pipelines or independent producers, future exploration and production costs should average out to the costs underlying the Commission's area rate determinations (R. 581, 637-653, 656, 671-673, 2164, 3061, 3086-3090). In this respect, it was shown that drilling costs were similar on an average basis for pipelines, their affiliates and independent producers (R. 5857-5868) and that these three types of producers have been equally successful within narrow limits in exploratory and developmental drilling (R. 5824-5827). In addition, it was explained that new explorations for gas are often undertaken jointly by pipelines and independent producers, 10/ so that exploration, development and production costs will frequently be identical (R. 581, 3060-3061).

9/ Petitioners' assertion (Br. p. 30) that the examiner did not find cost comparability with respect to gas from subsequently acquired leases, the only gas here involved, is incorrect. As the examiner recognized (R. 10127), costing approaches using historical costs distort this current reality.

10/ As of December 31, 1962, 49.1% of all pipeline and affiliated companies' wells outside of the Appalachian Area were jointly owned with other producers. When the Appalachian Area, which contained only 243 jointly-owned wells, was included, this percentage dropped to 23.9% (R. 6025).

The increased costs of exploration and development make such joint ventures increasingly likely to continue (R. 3060-3061).

Petitioners' contention (Br. p. 37) that the use of industrywide average costs cannot be made applicable to pipeline production from new leases is based on the fact that historically pipeline production costs have shown a considerably greater spread from the mean average industry cost than has been the case for independent producers (R. 5908-5909, 11284-85). But these variations, as the Commission explained (R. 11285), do not indicate anything more than the wide variation in costs at the divergent times when individual pipelines entered the production activity. In this respect, the Commission (R. 11284-11285) and the examiner (R. 10127), as had various witnesses (R. 3615-3616, 4098, 5908-5910), pointed out that pipeline producers fall into two primary categories: "low cost" ones, those who have been in production activities for many years and have acquired large reserves at very low prices prior to World War II and "high cost" producers, those who entered into the production area after the great industry expansion which followed the war. In these circumstances, as we have discussed, there is every indication that production costs from future acquired leases are no more likely to diverge significantly over time from the average industrywide cost for pipelines than independent producers.

B. <u>The Commission Was Fully Warranted in Concluding that Costing Pipeline Production from Future Acquired Leases on the Basis of Area Rates Would Benefit the Consuming Public Both by Minimizing Gas Costs and by Encouraging Increased Searching Activity by the Pipelines</u>

Petitioners mistakenly rely on the examiner's unsupported conclusion that the application of area rates to pipeline pro-

duction from future acquired leases would cause higher rates to the consumer. To the contrary, the Commission properly concluded (R. 11285) that the use of area rates may lead to reduced gas costs.

As the Commission pointed out (R. 11283), the individual cost-of-service approach, which permits the pipelines to charge as a cost of operation the expenses incurred in the development of new reserves, has generally led to high-cost pipeline produced gas in recent years (R. 584, 2206-2207, 2227-2229, 6177, 6189), 11/ although the relative amount of pipeline production has been declining. 12/ It may be that this high-cost gas has resulted from the fact that under this approach the pipelines have had little incentive to hold down costs. To be sure, the Commission has authority to disallow expenditures by a pipeline as excessive or improvident, but in practice, as the parties and the Commission recognized here, this power is quite limited (R. 721, 4218, 11285). In any event, whatever the reason for such high-cost gas, the Commission quite properly concluded that the consumer should normally not be saddled with a pipeline's

---

11/ The low cost of pipeline production involved in various cases where the pipelines sought to use the unregulated field price of gas as their cost was the result of the low acquisition cost of old production leases acquired long before the development of the natural gas industry as we know it today (R. 581, 4098).

12/ The Commission found very significant the evidence in the record submitted by its staff that pipeline and pipeline affiliate on-system reserves have not kept pace with total reserves in the continental United States. In 1960 these reserves amounted to 10.8% of total reserves while in 1965 they comprised only 8.9%, declining from 28,396,480 Mcf to 24,557,385 Mcf (R. 5747).

production costs that are higher than the ceiling price for producers under area rate regulation. At the same time, the pipelines could not reasonably be expected to invest in production activity if they could cost their production only at their own costs or the area rate, whichever was lower, for then they would bear the entire risk of not meeting average expectations without the possibility of a return commensurate with such a risk.

Conversely, if pipelines, as many of them have claimed in this proceeding, will attempt to conduct increased production operations if they are afforded the opportunity to receive the area rate fixed for producers (R. 644, 652-653, 711-712, 3092-3094, 3182-3183), the Commission was on sound ground in concluding that the consumers should not be deprived of increased searching and production by industry elements particularly interested in maintenance of adequate gas supply merely because the resultant returns--at prescribed area rate levels--might occasionally exceed the rate of return allowed a pipeline on its overall operations. At present, many of the natural gas pipelines have diversified into many other activities, including, as the Commission observed (R. 11283), operations more risky than gas production. By costing pipeline production at the area rates, the Commission is providing these companies with an alternative use for their venture capital that offers the same incentive as is available to producers--the possibility of beating the averages through a combination of skill, prudence, economy and luck. In view of the history of pipeline diversification and

the relative decline of pipeline production, there is plainly no reason to assume that a continuation of the cost-of-service approach would result in the investment of a comparable amount of pipeline capital in production activity.

Moreover, by permitting pipelines to cost their production from new leases at the area rate, the Commission is using price, as it did in Permian, supra, p. 13, as a tool for encouraging the pipelines to direct their searching activities specifically to finding gas reservoirs. On the other hand, the cost-of-service approach, which was adopted before the recognition of the directional searching relies on the average of current and historical costs, and hence does not provide the same gas supply eliciting tool.

As we have seen, the Commission's conclusion that the consumers should not be saddled with pipeline production costs from new leases higher than the price for gas purchased from producers at area rates was not dependent on the indications of gas shortage to which it referred (R. 11284). But the decline in the nation's inventory of gas reserves which the record disclosed certainly provided an added impetus to change the policy with respect to costing pipeline production from new leases so as to expand the universe of enterprises that might be encouraged to undertake large scale exploration and development for gas reserves.

Petitioners also contend (Br. pp. 43-44) that the consumer interest would suffer by using area rates for pipeline production because producing pipelines would no longer have incentive

to bargain for lower rates with independent producers. But as the Commission and the courts have long recognized, the "bargaining" of pipelines in the past has not placed any material restraint on price increases, in large measure because pipelines could generally pass on their gas supply costs. In Permian, the Supreme Court noted that history in upholding the Commission's rejection of a producer claim that price regulation should primarily reflect contract prices (390 U.S. at 792-794). But while pipeline bargaining motivation has been highly diluted in the past, pipelines are increasingly meeting competition from other fuels. In these circumstances, increased production activity by pipelines rather than removing incentive to bargain, as petitioners suggest, may strengthen their bargaining position by increasing the supplies of gas available and thereby lessening dependence on gas from independent producers.

Petitioners' contention (Br. pp. 25, et seq.) that the Commission's opinion is of dubious validity because it fails to comply with the teachings of this Court in City of Detroit v. F.P.C., 97 AppDC 260, 230 F. 2d 810 (1955), certiorari denied, 352 U.S. 829 (1956), is without any substance. In Detroit, this Court set aside the Commission's 1954 decision to value all of Panhandle Eastern Pipeline's gas production on the basis of field prices charged by producers prior to the regulation of producer prices by the Commission, instead of using the cost-of-service method. And this unregulated field price, which was computed on the basis of the "weighted average arm's length prices" established for similar gas in the fields,

was held not to reflect the lowest reasonable price consistent with the maintenance of adequate service. Indeed, the Supreme Court's decision in Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), establishing Commission jurisdiction to regulate independent producers, which was issued after the Commission's Detroit decision but prior to this Court's, made clear the need to regulate such field prices. In Detroit the effect of the changed approach adopted by the Commission there would have been to increase Panhandle's gas prices by 1.3 cents per Mcf. This Court, while specifically stating that the individual company cost-of-service method was not mandated by the Natural Gas Act (97 AppDC at 265, 230 F. 2d at 815), 13/ nevertheless stated that costs must be used as an anchor to hold the terms "just and reasonable" rates to some recognizable meaning. Further, the Court stated that if the Commission contemplated increasing rates for the purpose of encouraging exploration and development of pipeline production facilities, it must see to it that the increase is in fact needed, and is no more than is needed for the purpose.

Petitioners' claim that this case is a rerun of Detroit is plainly misconceived. As we have pointed out, the assertion that the new policy will result in rates higher than under

---

13/ The fact that the Commission is not compelled to use the individual company cost-of-service approach had been made clear in F.P.C. v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944); Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581 (1945); as the Supreme Court recently reexplained in Permian, 390 U.S. at 775.

individual company cost of service is unsupported. Moreover, area prices not only provide a cost anchor but, as we have discussed, the new gas prices under the area rate approach that would be applicable to gas from future acquired leases are designed to reflect the economic or current cost of finding and producing gas, including the return needed to induce investment in that activity. In other words, it is intended to reflect the minimum price needed to elicit new gas supplies. Accordingly, it seems clear that the decision here is fully consistent with the teachings of Detroit.

II. THE COMMISSION REASONABLY DETERMINED THAT PIPELINE PRODUCTION FROM FUTURE ACQUIRED LEASES SHOULD BE TREATED ON A PARITY WITH PRODUCTION BY INDEPENDENT PRODUCERS

The Commission, as we have previously shown, found that the most meaningful indication of the current costs involved in the production of natural gas from fugure acquired leases was not the costs incurred by an individual company in a certain test year but rather a composite of the costs incurred by the industry. By treating the future production activities of a pipeline, not as a component of the pipeline's transmission business, but essentially as a separate producer, the Commission seeks to encourage exploration and development of reserves by pipelines while providing more effective regulation over the costs of gas from these reserves.

The same technology, costs and risks involved in production from newly-acquired leases by independent producers apply

similarly to pipelines. Therefore, the Commission reasonably concluded that if pipelines were to act as other producers in acquiring and developing new leases, the same regulatory approach should apply without the modifications with respect to return and taxes that petitioners apparently seek.

A. <u>The Commission's Allowance of the Same Overall Return for Pipelines As Other Producers Was Reasonable</u>

Petitioners contend (Br. pp. 45-50) that use of the area rates determined proper for independent producers is inappropriate for pipeline producers because the use of the same return component will result in excessive returns on equity for pipeline producers. The Commission properly found (R. 11286) that this claim, urged upon it by the staff in support of modified area rates for pipeline production, was not soundly based. We may note that the staff, recognizing that excessive costs were likely to result from use of the individual company cost-of-service approach for subsequently acquired leases and the desirability of utilizing the incentive pricing technique devised in <u>Permian</u>, proposed a shift from the individual company cost-of-service approach (R. 10329-10330) to an area rate approach of some type.

The claim pressed by petitioners that the overall return used to fix area rates for independent producers would be excessive for pipelines (though on the average the rates would be less than under cost of service) rests (1) on the fact that historically the overall financing of interstate pipelines has relied much more on debt financing than has been the case with

independent producers and that such debt has been cheaper than equity money, 14/ and (2) the assumption that debt capital will finance _new_ pipeline investments in producing properties in the same proportion as used for total corporate investments. 15/ The Commission, in rejecting these speculations, refused to assume that in the future pipelines would, under the area rate approach, be in a position to utilize their debt resources for the riskier production activities to the same extent as for transmission facilities. For once the risks of pipeline production cease to be borne by the ratepayers, pipeline investments in production properties will cease to have essentially the same financial security as transmission investments (R. 952). Moreover, excessive use of debt financing for highly risky ventures could well affect the cost of debt to the pipeline.16/

14/ The record showed that producing pipelines had an average capitalization in 1966 of 49.35% equity and 50.65% debt (R. 6144). Independent producers in 1966 had an average capitalization of 76.53% equity and 23.47% debt (R. 6145). However wide variations are found within these two groups also. In 1966, for example, individual producing pipelines had from 22.25% to 77.67% debt capitalization. Independent producers' debt capitalization varied from 68.99% to 4.38%.

15/ The staff witness who also made this assumption also recognized, however, that each dollar spent could not in fact be traced back to its original point of entry in the corporation (R. 1097).

16/ In addition, acceptance of the assumption that pipelines would use their debt proportionately for all investments would correlatively mean that high debt pipelines might well be entitled to a greater allowance on the equity for their new lease production than very low debt companies. Thus, the equity earnings of companies with markedly different capital structures cannot properly be directly compared. A relatively high proportion of long-term debt such as pipelines have creates a risk for the equity that may entitle the equity to a higher return than otherwise. See _El Paso Natural Gas Co._,

Petitioners' claim (Pet. Br. 45-46) that allowance of a 12 percent return would, because of the different capital structures of pipelines and independent producers, translate into a 20-40 percent return on the equity theoretically assigned by them to the pipeline production function is also highly misleading because the computation (R. 503, 4262) assumes that future debt financing will be at the low historical levels reflected by the imbedded debt costs of pipelines in 1962. 17/ It is clear that to the extent debt is used for financing future gas searching activity it will be debt raised at current interest levels. Whether these rates for pipeline debt financing will remain at the 8-1/2 percent demanded at the time of the Commission's opinion in October 1969, or the present level of more than 9 percent, it is apparent that the low debt costs of the past utilized by petitioners in their computations are now only a matter of historic interest.

In these circumstances, the Commission was justified in concluding that the differences in overall capital structures of independent producers and interstate pipelines did not provide any meaningful basis for believing that the overall cost of financing new production activity would be markedly cheaper

---

28 FPC 688, 700-702 (1962). Conversely, the relative thickness of equity, such as the average equity of 85% in Permian, indicates less financial risk to the common stockholder than exists in enterprises with thin equity.

17/ The same fallacies underly the computations (Pet. Br. p. 48) based on using an area rate with a 6-1/2 percent return in lieu of the twelve percent used in Permian.

for pipelines than independent producers or that pipeline return on equity with respect to their gas production from future leases would differ materially from those of independent producers. The Commission was also on sound ground in pointing out that even if the pipelines were able to utilize their resources to produce gas from future developed leases at lower average costs than independent producers, failure to permit the pipeline to retain such differential would greatly diminish the incentive built into area pricing, i.e., the opportunity to reap the reward of their luck, efficiency and prudence. At the same time, as discussed supra, the public is protected by the area rate concept from bearing the brunt of unnecessarily high-cost pipeline production efforts.

B. The Commission's Decision to Allow Parity for Pipeline Producers in Treatment of Possible Income Tax Benefits Was Rationally Based

The thrust of the Commission's decision in these proceedings was to treat all future production activities whether by a pipeline or by an independent producer on an equal basis. Not only did the Commission intend to provide a more accurate measure of the costs involved in future production, but also through equal treatment the Commission hoped to place all segments of the production industry on a competitive par and intensify the exploration for natural gas (R. 11282, 11290). The Commission, consistent with these objectives, held that pipeline producers would be allowed to utilize any possible federal income tax benefits resulting from new production activity to the same extent as independent producers. Petitioners' objec-

tions (Br. pp. 51-56) that this result is inconsistent with the goal of consumer protection is not valid.

In the Permian 18/ and Southern Louisiana 19/ proceedings, a zero tax allowance was included in the cost determination since on the record it could not be shown that, on an area-wide basis, the independent producers would pay federal income taxes. Similarly, in these proceedings, most of the parties agreed (R. 5420-5433) that, on the record, neither a negative nor a positive tax on future production activities by pipelines could be assumed. However, as the Commission stated, it was to be expected that at any given point in time some pipelines would be able to show that they paid taxes on their production activities and others would have tax credits, i.e., deductions in excess of their gas production income (R. 11288). 20/

18/ 34 FPC 159, 206 (1965), affirmed, 390 U.S. 714 (1968).

19/ 40 FPC 530, 585 (1968), affirmed, Southern Louisiana Area Rate Cases, CA5 No. 27492, March 19, 1970.

20/ Petitioners point out (Br. p. 55 and n. 105) that specific pipelines have in the past had tax deductions from production operations that were sufficient not only to eliminate any taxes on such activities but also to reduce taxes on other activities. But the record data (albeit a hypothetical study) to which they refer also indicates that for the year cited the producing pipelines as a group may have paid taxes on their production properties (R. 6161-6162, 4274, 4277-4280). Further, it was pointed out on the record that viewing taxes for an individual producer on the basis of a single year fails to show the true tax picture for producing properties. In the first years of an extensive exploration and development program, deductions are greatest while income from the property is small. Over the years, however, deductions decline while taxable income from this property increases (R. 4279-4280, 6165).

Under traditional pipeline cost-of-service regulation, such tax credits would be first used to offset any taxes due on production activity, then the remainder would be used to offset taxes due on the transmission activities of the pipeline. Although pipeline producers have sought to retain these earnings as an incentive to expand production activities, the Commission and the courts have held that this approach would be inappropriate under individual cost-of-service regulation. In El Paso Natural Gas Co. v. F.P.C., 281 F. 2d 567 (CA5, 1960), certiorari denied sub nom. California v. F.P.C., 366 U.S. 912 (1961), the court stated that under individual company cost-of-service the inducement to greater production was a function of the allowable rate of return. If the Commission wished to afford a company additional incentive, it would have to reflect this in the rate of return, not by "merely treating the tax savings as the amount necessary to provide for return and incentive." Id. at 573. Similarly, the Fourth Circuit in Cities of Lexington v. F.P.C., 295 F. 2d 109 (CA4, 1961), rejected the pipelines' position that the Commission consider "these unusual concessions in the tax statutes as devices for the benefit of the producer" stating in part, that "it must be kept in mind that we are not dealing with an enterprise which itself takes all the risk, but with a regulated industry * * * which is protected by the requirement that in fixing the rates all elements of cost must be considered which pertain to the original investment, the depletion of capital assets, the

costs of operation and the costs of exploration." Id. at 116. 21/

While this is an apt description of how these operations were governed under individual company cost-of-service, the Commission pointed out this approach is not applicable where future production activities are being regulated on an area basis since under this method the price allowed for gas taken into their systems is unrelated to the individual company's cost, rate of return considerations, or tax situation (R. 11289). Indeed a predicate of the composite return used in the independent producer rates is the possibility that an individual producer may have such tax benefits available to it. If pipelines were disallowed such benefits while receiving the same rates, they would in fact be short changed and not be accorded the same incentives as producers.

Requiring a pipeline to use any future tax benefits which might possibly occur from its production activities related to future acquired leases to offset taxes on its transmission activities would put these companies at a competitive disadvantage with independent producers who may utilize these benefits in any way

---

21/ In City of Chicago v. F.P.C., 128 App DC 107, 385 F. 2d 629 (1967), certiorari denied sub nom. Public Service Commission of Wisconsin v. F.P.C., 390 U.S. 945 (1968), this Court stated "natural gas pipelines have no need for the additional capital provided by tax reserves to finance expansion in view of the regulatory principles under which rate of return is established so as to attract new capital and there is provision for adequate working capital allowance in the rate base." Id. at 635-636.

they see fit and would also tend to discourage large-scale exploratory efforts by undermining the incentives built into area rates. Petitioners' claim that this policy will saddle the consuming public with unnecessary costs by depriving it of spillover benefits which could be used to reduce the taxes paid on the transmission activities is plainly unsound when viewed in this context. 22/

III. PETITIONERS ARE WRONG IN CLAIMING THAT THE COMMISSION DID NOT DECIDE THIS PROCEEDING ON THE BASIS OF THE HEARING RECORD

Petitioners' final contention (Br. pp. 57-69) that the Commission improperly converted this from an adjudicatory proceeding to rulemaking seems to boil down to a claim that the Commission allegedly based its decisions on matters not presented in evidence and of which it could not take official notice. As the Commission's decisions show, this is plainly not the case.

Before discussing the basic claim that the Commission's action was improperly based on matters outside the record, it seems appropriate to point out that the present case could at no point be characterized as adjudicatory within the mean-

---

22/ Petitioners also contend that since the Commission imposes no requirements to plow back tax credits into production operations the possibility exists that these credits could be used for nonjurisdictional activities. The Commission recognized the possibility that some pipelines, like some independent producers, might do this; however, it found that this is no reason to disadvantage pipelines as a whole. Furthermore, since these credits apply only to future production activities, they would be earned only to the extent that pipelines in fact did explore for and develop new reserves (R. 11360).

ing of the Administrative Procedure Act simply because it was to be decided on the basis of a formal, evidentiary type hearing record. To the contrary, the Administrative Procedure Act defines rulemaking to include the prescription of rates for the future as well as statements of policy. 5 U.S.C. 551(4). The fact that the Commission decides to take action of such type on the basis of a formal record, even if not required to do so by the statute, does not change the rulemaking character of the proceeding.

In any event, the claim that the Commission ignored the hearing record to decide this proceeding is baseless. As we have discussed, the Commission determined, on the basis of its precedents and the evidentiary record here, that the reasons underlying the irrationality of pricing the production of gas on an individual company cost-of-service basis for independent producers which have been recognized by the courts also applied to the production of gas by pipelines from future acquired leases (R. 11282-11283). The Commission found, based on the record, that exploration and development operations of both independent producers and pipeline operators were similar and could be expected to remain similar in the future (R. 11361-11362), that the costs of future production activities of independent producers and pipeline producers should be similar (R. 11285), and that once area rates had been determined the cost-of-service approach for gas from future acquired leases by pipelines was likely to load unnecessary costs on consumers.

And while the Commission found that pipeline owned production did not justify excessive costs such as would result in

the aggregate from the individual cost-of-service approach, it concluded that the consumer would benefit by providing the pipelines the incentive to engage in increased gas searching activity on the same terms as producers. The Commission properly found that involving more entities in this activity was particularly desirable since the record showed a continuing decline in the inventory of the nation's gas reserves. In this respect, it also noted the 1968 American Gas Association data showing that in 1968 the net production of natural gas for the first time exceeded reserves added and generally that there were indications that increased drilling activity was needed to provide the surging demands for gas. 23/ But the Commission's expressed concern over the indications of a gas shortage, gleaned from both the record and later data updating statistical series in the record, 24/ in no way supports the claim that other relevant matters of record were ignored. As discussed above, the contrary is plainly the case.

Petitioners' related reliance on this Court's decision in Cinderella Career & Finishing Schools, Inc. v. F.T.C., slip opinion (CADC No. 22624, March 20, 1970), is also singularly misplaced. In that case, the F.T.C. reached its decision on whether certain

---

23/ The Fifth Circuit has similarly expressed its concern with respect to the gas supply problem in two recent Commission cases. See Southern Louisiana Area Rate Cases, CA5 No. 27492, March 19, 1970 (e.g., slip op. pp. 52-56); Hunt Oil Co. v. F.P.C., CA5 No. 27457, April 21, 1970 (slip op. pp. 11-12).

24/ In Permian, the same type of updated post-record data was relied upon by both the Commission and the Supreme Court. E.g., 390 U.S. at 816, n. 100.

newspaper advertising was false, misleading, and deceptive on the basis of a de novo review of these advertisements, purposely ignoring the testimony adduced at the hearing of expert and consumer witnesses. Id. at 3-4. This Court held that while the Commissioners may review determinations made by the hearing examiner concerning the credibility of witnesses and exclusion of hearsay evidence, it may not choose to ignore completely the testimony adduced at the hearing. "[W]e do not say that the Commission must find an examiner's findings of fact and conclusions of law 'clearly erroneous' before overturning an initial decision, but we do say that it must consider that decision and the evidence in the record upon which it is based, rather than dismissing the proceedings at the hearing out of hand." Id. at 10-11.

Here the Commission carefully considered the examiner's decision as well as the record and adopted many of his findings of fact. However, it reasonably differed as to the conclusions that should be drawn from these findings. (R. 11361.)

CONCLUSION

For these reasons, the orders of the Commission should be affirmed.

Respectfully submitted,

Gordon Gooch,
General Counsel,

Peter H. Schiff,
Solicitor,

Abraham R. Spalter,
Assistant General Counsel,

Joseph J. Klovekorn,
Attorney,
For Respondent.

Federal Power Commission,
Washington, D. C. 20426.

June 15, 1970

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ILLINOIS, CITY AND COUNTY OF DENVER, COLORADO, THE MEMPHIS LIGHT, GAS AND WATER DIVISION, MEMPHIS, TENNESSEE AND THE AMERICAN PUBLIC GAS ASSOCIATION,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent.

BRIEF FOR INTERVENOR PENNZOIL PRODUCING COMPANY

J. C. OHRT
General Attorney
Pennzoil Producing Company
900 Southwest Tower
Houston, Texas 77002

WILLIAM B. CASSIN
Baker, Botts, Shepherd & Coates
1600 Esperson Building
Houston, Texas 77002

June 15, 1970

FIDELITY PRINTING COMPANY, INC., HOUSTON

TABLE OF CONTENTS

TABLE OF CASES

United States Court of Appeals

For the District of Columbia Circuit

No. 23740

City of Chicago, Illinois, City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee and the American Public Gas Association,

Petitioners,

v.

Federal Power Commission,

Respondent.

BRIEF FOR INTERVENOR PENNZOIL PRODUCING COMPANY

STATEMENT OF ISSUES PRESENTED FOR REVIEW

1. Is the Federal Power Commission (FPC) prohibited from regulating rates for gas produced from future-acquired leases by pipelines and their affiliates under an area rate system which has been found to be lawful under the Natural Gas Act?

2. Were the orders under review justified in the record?

STATEMENT OF THE CASE

The FPC proceeding leading to the action under review here was initiated by order[1] of the FPC which directed the examiner to determine in Phase I what is the most appropriate pricing method to be applied to "new" on-system natural gas, *i.e.*, gas utilized in a pipeline's interstate system (on-system) which is produced by the pipeline or its

[1] 35 FPC 497 (1966), R. 7110.

affiliated producing company from leases acquired after the date of determination of this issue.[2] The FPC expressly reserved for later consideration in Phase II (which at this date has not commenced) the problem of pricing "old" on-system gas, *i.e.,* on-system gas produced from leases acquired on or before the date of determination of the Phase I "new" gas issue.

On April 17, 1969, the examiner's initial decision was published. In this decision the examiner rejected the various conclusions urged on him by the respective parties, and recommended a hybrid pricing policy, of his own invention, which was intended to vitiate the ill effects that he expressly found to flow from an individual company cost of service pricing policy. R. 10129.

The examiner's decision was excepted to by the FPC staff and *all* other parties here, including the Municipal Gas Group (Petitioners in the case at bar). After hearing extended oral argument, the Commission issued its Opinion No. 568 and concurrent order on October 7, 1969, and later modified same in part by Opinion No. 568-A and concurrent order denying rehearing issued December 5, 1969.

In its opinions and orders here under review, the FPC adopted the examiner's findings and conclusions to the extent they are not inconsistent with those expressed by the FPC. R. 11361. The end result reached by the FPC diverged from that of the examiner, however, in that the FPC concluded that pipeline and affiliate producers are to be treated on a parity with independent producers, *i.e.,* that "new" on-system gas should be priced under the area rate pricing method. In reaching this result, the FPC articulated a number of very important findings and conclusions which are set out in summary form below:

1. There are at least four sound reasons why prices based on individual company cost of service should not be applied to "new" on-system gas:

---

[2] The Commission's determination was handed down in Opinion No. 568 and concurrent order on October 7, 1969. By its terms, the determination does not affect on-system gas produced from leases acquired on or before that date.

a. The incongruities and administrative difficulties cited in *Phillips II*[3] and *Permian*[4] as reasons why individual company cost of service pricing is not feasible or workable for production by independent producers apply with equal force to production by pipelines and their affiliates.

b. Application of individual company cost of service to "old" on-system gas has, in the past, resulted in higher gas costs to consumers and proportionately less production by pipelines.[5]

c. Exploration and production activity by pipelines should be encouraged, not discouraged as it has been in the past under individual company cost of service.

d. Use of the area rate system in pricing "new" on-system production will benefit the consumer (i) by encouraging more gas exploration, and (ii) by discouraging needlessly expensive production activities which have resulted in the past from using individual company cost of service as the pricing method for on-system gas produced by pipelines.

2. There is no evidence that the cost of "new" on-system gas production, on the average, will diverge significantly from independent producer "new" gas production costs, on the average. In other words, use of the area rate pricing method for "new" on-system gas cannot be found likely to result in exhorbitant profits for pipelines and affiliates unless the same can be said of independent producers.

3. Pipelines and their affiliates cannot finance exploration and development activities at a lower money cost than independent producers.

---

[3] *Phillips Petroleum Co.*, 24 FPC 537, aff'd *sub nom. Wisconsin* v. *FPC*, 303 F.2d 380 (D. C. Cir., 1961), aff'd, 373 U.S. 294 (1963).

[4] *Permian Area Rate Proceeding*, 34 FPC 159, aff'd, *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

[5] As will be discussed hereinafter, affiliates have always been accorded the same rate regulation as independent producers and have not been regulated in the same manner as pipeline producers.

4. If the rates applied to "new" on-system gas are discounted from the rates allowed "new" independent production, this will virtually guarantee that pipelines and their affiliates will not engage in the exploration and development activities required to find significant quantities of "new" on-system gas reserves.

The Statement of the Case in the Petitioners' brief might lead one to believe that the FPC did not articulate a single one of the foregoing findings and conclusions but rather simply threw out the examiner's work, ignored the record entirely, and resorted to extra-record speculations about gas shortages to justify giving pipelines and their affiliates "higher rates" amounting to hundreds of millions of dollars. This simply is not true. Instead, as will be demonstrated hereafter:

1. The FPC carefully evaluated all the record evidence examined by the examiner and based its findings and conclusions on this evidence.

2. The FPC found that its actions challenged on this review would not result in higher rates for consumers. Indeed, the clear implication of the FPC's opinions is that limiting "new" on-system gas to independent producer prices will result in *lower* rates for consumers.

3. Finally, the FPC found, as did the examiner, that use of individual company cost of service in pricing "new" on-system gas would be contrary to the public interest since it would discourage the search for "new" on-system reserves at a time when the record shows such "new" reserves must be found if the interests of gas consumers are to be given the full protection required under the Natural Gas Act.

ARGUMENT

SUMMARY

The remaining portion of this brief is divided into four sections dealing with the following subjects:

1. Correction of the erroneous premises in the Petitioners' brief.

2. A discussion of the principal findings and conclusions of the FPC and the evidence and authorities supporting same.

3. A refutation of the Petitioners' allegations concerning "rule making" and the *Cinderella*[6] case.

4. A brief discussion of the current severe gas shortage as it pertains to the case at bar.

1.

The Erroneous Premises in Petitioners' Brief

There are four principal erroneous premises from which substantially all of the arguments in Petitioners' brief proceed. This section is devoted to highlighting and correcting such premises.

A. The orders at issue in this case do not affect "old" on-system gas, but rather only "new" on-system gas.[7]

At page 7 of their brief, Petitioners admit, as they must, that the orders at issue in the case at bar are expressly limited so that they do not affect "old" gas, *i.e.,* gas produced from leases acquired on or before October 7, 1969. The proper pricing of this "old" gas for rate making purposes simply is not in issue at the present time, and will not be dealt with by the FPC until it initiates, at some time in the future, Phase II of the proceedings in Docket No. RP66-24 below.

Notwithstanding the foregoing, most of the arguments in the petitioners' brief carry the clear implication that pricing of "old" on-system gas is in issue here. This implication comes closest to the surface at pages 47 and 48 of Petitioners' brief where figures based solely on "old" gas production are put forward in an effort to make the court believe that the FPC's decision with respect to "new" gas will cost consumers hundreds of millions of dollars. The figures conjured up

---

[6] *Cinderella Career and Finishing Schools, Inc.* v. *FTC,* .... F.2d .... (D.C. Cir. 1970).

[7] As used in this brief, "new" gas means gas from leases acquired after October 7, 1969, the date of the FPC's principal order here under review. "On-system" gas is gas utilized in a pipeline's interstate system which is produced by the pipeline or an affiliated producing company.

at this point by Petitioners are so patently fallacious that neither the examiner nor the FPC saw fit to dignify them by citation. Petitioners are not embarrassed by the illogic of their argument, however, apparently because they are so preoccupied with the possibility that the decision reached with respect to "new" gas may somehow affect the decision to be reached some years hence in Phase II of RP66-24 with respect to "old" gas.

It is understandable that Petitioners want to be vigilant that the issues in Phase II are not prejudged by the decisions reached in Phase I. However, this does not justify the Petitioners' consistent resort to inapt "old" gas statistics, precedents, arguments and concepts in their effort to show error in the FPC's decision on the pricing of "new" gas.

B. The FPC did not grant pipelines and their affiliates "rate increases" in the orders here being reviewed but rather simply decided that on-system gas not yet found from wells not yet drilled on leases not yet acquired will cost the consumer no more and no less than the same gas would cost if found and produced by an independent producer.

The Petitioners' brief is replete with inflamatory phrases such as, "Proponents of increased profits . . ." (page 5), "The parties asking higher rates . . ." (pages 8 and 42), "If the Commission contemplates increasing rates . . ." (page 21), "to protect consumers against unjustified profits . . ." (page 25), "replay of . . . City of Detroit . . . in an attempt to obtain a higher price . . ." (pages 25-26), "impose a staggering burden on the nation's gas consumers . . ." (page 47), and "The consuming public thereby will be saddled with additions to the cost of service . . . by the increase in gas price (via area rates) . . ." (page 55).

What the Petitioners choose to ignore is the evidence in the record that use of individual company cost of service with a pipeline utility rate of return and flow through of tax loss "spillovers" in pricing "new" on-system gas will result in there being no "new" on-system

production — or a *de minimis* quantity at best.[8] Hence all "new" gas flowing to consumers will of necessity be that produced by independent producers and will obviously be priced under the area rate pricing method. In other words, with pipelines and affiliates being forced out of the on-system "new" gas business, such "new" gas as the consumers do receive will come solely from independent producers and thus will be priced at exactly the same prices as it would if pipelines and affiliates were granted price parity for "new" on-system gas as directed by the FPC in the orders here under review. This fact of life was recognized by the FPC in setting the method for pricing "new" on-system gas.

Both the examiner and FPC found that pricing "new" gas in the manner advocated by Petitioners would result in substantial if not complete elimination of pipelines and their affiliates from the business of searching for and producing "new" gas. As the examiner said:

> "If the pipelines' production of new gas is priced at a straight cost-of-service level, there are notable indications that such pipeline production might be reduced. * * * *Some regulatory relief is in order, otherwise pipeline production might diminish unduly.*" R. 10129. (Emphasis supplied.)

And as the FPC said:

> "This [the staff's modified cost of service recommendation] is virtually guaranteed to discourage pipelines from entering the production area to any major degree." R. 11286-87.

It cannot be emphasized too strongly that the pipeline and affiliate respondents did not ask the FPC for a "rate increase" in the proceeding below, nor did the FPC grant one. These respondents merely asked and were granted pricing parity with other regulated entities — independent producers — engaged in the non-utility activity of exploring for and producing "new" gas. As the FPC pointed out this will not increase gas costs to consumers but rather will protect them from bearing the brunt of "unsuccessful or otherwise unnecessarily high-cost pipeline production efforts." R. 11287.

From the foregoing it is clear that the orders here challenged cannot result in increased gas costs to consumers and most likely will

[8] The FPC's and examiner's findings on this point and the record supporting same are thoroughly discussed and documented herein beginning at page 18, *infra*.

result in a lowering of such costs. These orders thus fall squarely within the "primary orientation" of the Natural Gas Act so vigorously articulated by this court in *City of Detroit* v. *FPC,* 97 App. D.C. 260, 230 F.2d 810 (1955), cert. denied, 352 U.S. 829 (1956).

C. The on-system gas prices of affiliates, such as Pennzoil Producing Company, have always in fact been regulated in the same manner as prices of independent producers and there has been no showing in this case such as is required by City of Detroit to justify a change.

Throughout Petitioners' brief, a third erroneous premise is constantly advanced in that affiliate production activities are lumped with pipeline production activities, and the 1945 *Colorado Interstate* case[9] and recent *Continental* case[10] are cited as authority for the regulation of affiliate on-system production on a cost of service basis. (Petitioners' brief, pages 17 and 24.) The fact is, however, that affiliate on-system production has always been regulated on the same basis as independent producer production. *Pro forma* cost of service recitations notwithstanding, that is unquestionably the end result reached in the settlements approved by the FPC in the only two cases directly in point; *i.e., Northern Natural Gas Co.,* 29 FPC 4 (1962), 29 FPC 689, 30 FPC 1364 (1963); and *Union Producing Co.,* 31 FPC 41, 31 FPC 503, 32 FPC 1506 (1964).

At one point or another in the proceedings below the Petitioners here and parties aligned with them cited many cases as purportedly holding that affiliates' on-system sales must bear cost of service prices. Neither the 1945 *Colorado Interstate* case, nor the recent *Continental* case currently relied on by Petitioners, nor any of the other cases similarly relied on earlier supports the proposition for which they have been cited. We have read all of the twenty-one citations advanced on this point and find that fifteen, including the 1945 *Colorado Interstate* case, were plain and simple cases where the pipeline in question

---

[9] *Colorado Interstate Gas Co.* v. *FPC,* 324 U.S. 581 (1945).

[10] *Continental Oil Co.,* 39 FPC 1034 (1968), aff'd *sub nom. Cities Service Gas Co.* v. *FPC,* ¶ 11,093 ULR Federal, (10th Cir. 1969).

produced some of the gas which it transported and sold in interstate commerce;[11] one involved a spin-off of producing properties from a pipeline to its affiliated producer;[12] one — the recent *Continental* case — involved a pipeline's spin-off of producing properties to an affiliated producer and the subsequent sale of the affiliate to an unrelated corporation;[13] and two were pipeline rate cases where an issue was made of the reasonableness of affiliated producer rates established in the era prior to regulation of such rates.[14]

The final two cases cited by those advocating cost of service or some variation thereof have been *Union Producing Co., supra,* and *Northern Natural Gas Co., supra.* Citation of these as cost of service cases is highly misleading since, as noted above, the end result of these cases was that the affiliate producer rates were fixed on the same basis as independent producer rates.

---

[11] *Home Gas Co.,* 2 FPC 402 (1941); *Canadian River Gas Co.,* 3 FPC 32 (1942); aff'd, *Colorado Interstate Gas Co.* v. *FPC,* 142 F.2d 943 (10th Cir. 1944), aff'd, 324 U.S. 581 (1945); *City of Cleveland* v. *Hope Natural Gas Co.,* 3 FPC 150 (1942), aff'd, *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591 (1944); *Panhandle Eastern Pipe Line Co.,* 3 FPC 273 (1942), aff'd, *Panhandle Eastern Pipe Line Co.* v. *FPC,* 324 U.S. 635 (1945); *Cities Service Gas Co.,* 3 FPC 459 (1943), aff'd, *Cities Service Gas Co.* v. *FPC,* 155 F.2d 694 (10th Cir), cert. denied, 329 U.S. 773 (1946); *Columbus, Ohio* v. *United Fuel Gas Co.,* 5 FPC 279 (1946); *City of Pittsburgh* v. *Pittsburgh and W. Va. Gas Co.,* 7 FPC 112 (1948); *Northern Natural Gas Co.,* 11 FPC 123 (1952), aff'd, *State Corp. Com'n of Kansas* v. *FPC,* 206 F.2d 690 (8th Cir. 1953), cert. denied, 346 U.S. 922 (1954); *United Fuel Gas Co.,* 12 FPC 251 (1953); *Hope Natural Gas Co.,* 12 FPC 342 (1953); *Panhandle Eastern Pipe Line Co.,* 13 FPC 53 (1954), rev'd, *City of Detroit* v. *FPC,* 230 F.2d 810 (D.C. Cir. 1955), cert. denied, 352 U.S. 829 (1956); *Colorado Interstate Gas Co.,* 19 FPC 1012 (1958); *Panhandle Eastern Pipe Line Co.,* 25 FPC 784 (1961), aff'd, 305 F.2d 763 (D.C. Cir. 1962), cert. denied, 372 U.S. 916 (1963); *El Paso Natural Gas Co.,* 28 FPC 688 (1962); *Southern Natural Gas Co.,* 29 FPC 323 (1963).

[12] *Northern Natural Gas Co.,* 12 FPC 66 (1953).

[13] *Continental Oil Co., et al.,* 39 FPC 1034 (1968), affirmed, *sub nom. Cities Service Gas Co.* v. *FPC,* ¶ 11093 ULR Federal (10th Cir. 1969).

[14] *United Gas Pipe Line Co.,* 14 FPC 353 (1955), rev'd, *Mississippi River Fuel Corp.* v. *FPC,* 252 F.2d 619 (D.C. Cir.), cert. denied, 355 U.S. 904 (1957); *United Gas Pipe Line Co.,* 25 FPC 26 (1961), rev'd on confession of error, *Wilmut Gas and Oil Co.* v. *FPC,* 299 F.2d 111 (D.C. Cir. 1962). See the discussion of the *Mississippi River* case in *American Louisiana Pipeline Co.* v. *FPC,* 344 F.2d 525, 532 (D.C. Cir. 1965).

To summarize, affiliate on-system gas sales have always *in fact* been accorded the same rate treatment as independent producer sales. From this fact of regulatory life, two results inevitably flow:

(1) Regulation of affiliate on-system "new" gas sales as independent producer sales will *not* raise gas prices since affiliate sales have always been regulated as independent producer sales.

(2) According affiliate on-system "new" gas sales any treatment other than that accorded independent producer sales must be justified on the record under the rule announced in the *City of Detroit* case.

There is no justification on the present record for changing the method of regulation successfully applied to affiliate producer rates by the Commission in the past and at the present time. Hence, such method — the independent producer method — should continue to govern affiliate producer rates now and in the future.

D. Individual company cost of service pricing is not the only legally permissible method for pricing on-system production.

If the arguments at pages 29-42 of Petitioners' brief are taken together, they may fairly be boiled down to the simple statement that individual company cost of service pricing is the *only* pricing method that may be applied to on-system production. This proposition — the fourth erroneous premise in the Petitioners' brief — is also patently wrong. Neither the FPC nor any court has ever so held and, indeed, many passages in leading cases, especially this court's opinion in *City of Detroit,* clearly indicate that other regulatory methods may be used in pricing on-system production. The import of the *City of Detroit* case to this effect was clearly recognized by the Supreme Court in *Permian* in its criticism of the ultimate circularity of computing rates based solely on costs. In this connection, see especially note 99 in the *Permian* decision where the Court cites *City of Detroit* in supplementing the following statement:

> "Nothing under the Act or the cases of this Court compels the Commission to reduce its regulatory functions to self-fulfilling prophecies." 390 U.S. at 816.

Furthermore, it is perfectly clear to an unbiased reader that the Court's rejection, in *Permian,* of the argument that area rates are impermissible under the Natural Gas Act is in no way limited to the situation of independent producers. The passage in question occurs at pages 774-777 of 390 U.S. Reports. We will not quote all of this extensive discussion, but it does seem appropriate to quote the Court's conclusion:

> "It follows that rate-making agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'" 390 U.S. at 776-777.

In addition to the foregoing, it must be noted that the FPC in fixing area rates has not limited its consideration to evidence peculiar to independent producers. Quite to the contrary, the FPC has based its area rates for "new" gas to a significant extent on evidence concerning the costs of pipeline and affiliate production,[15] and has made it clear that its inquiry in area rate cases is directed toward determining the costs and risks inherent in exploration and production *activities,* regardless of the entities by which such activities are undertaken. As the FPC said, "production *operations* inherently involve a greater degree of risk than the transportation of gas."[16] And, "financial requirements dictate that if unusual risks are *inherent* in production, a greater return should be allowed on investments therein in the absence of record evidence to support a different conclusion."[17]

To summarize, the FPC is not prohibited from applying area rates to "new" on-system gas. Moreover, the FPC's method for establishing the area rates that would apply to "new" on-system gas focuses on the production industry as a whole and utilizes on-system data and thus such method is entirely appropriate for the establishment of on-system "new" gas prices.

---

[15] This fact was specifically noted by the FPC in Opinion No. 568. R. 11286.

[16] *Area Rate Proceeding* (*Permian Basin Area*), 34 FPC 159, 201, 34 FPC 1068, aff'd, 390 U.S. 747 (1968). (Emphasis supplied.)

[17] *Ibid.* (Emphasis supplied.)

2.

The FPC's Principal Findings and Conclusions

As stated earlier, the FPC's orders which are before this court are based on four principal findings and conclusions:

A. There are good reasons why "new" on-system gas should not be priced on a cost of service basis.

B. There is no evidence that pipelines and affiliates can find and produce "new" gas more cheaply than independent producers.

C. Pipelines and affiliates cannot finance production activities at a lower money cost than independent producers.

D. Pipelines and affiliates must have price parity with independent producers or they will be forced to quit the "new" on-system gas business.

These four points will be separately discussed in the remainder of this section.

A. There are good reasons why "new" on-system gas prices should not be based on cost of service.

Although the FPC did not enumerate them as such in its Opinions Nos. 568 and 568-A, it articulated four sound reasons for departing from cost of service in pricing "new" on-system production. The first reason is that the incongruities and administrative difficulties cited in *Permian* and *Phillips II* as justifying abandonment of cost of service for independent producer rate regulation apply with equal force to pipelines and affiliates. These incongruities and difficulties may be summarized as follows:

> 1. "[T]he traditional original cost, prudent investment rate base method of regulating utilities is not a sensible, or even a workable method of fixing the rates of independent producers of natural gas."[18]

---

[18] *Phillips Petroleum Co.,* 24 FPC 537, 542 (1961), aff'd *sub nom. Wisconsin* v. *FPC,* 373 U.S. 294 (1963).

2. "Producers of natural gas cannot, by any stretch of the imagination, be properly classified as traditional public utilities."[19]

3. "The producer must invest his funds prior to ascertaining whether he will have anything to sell . . ."[20]

4. "[T]o fix rates of gas producers simply by allowing a return on investment or rate base will penalize the efficient or fortunate producer and will unduly reward the inefficient or unfortunate producer."[21]

5. "[T]he determination of the cost of a producer's assets upon the happening of a certain event, or at a certain point in time will produce unrealistic and inequitable results."[22]

6. "We are not dealing with a service requiring certain equipment at known costs."[23]

7. "[W]e are faced with the extremely difficult problem of allocating costs between the regulated and unregulated products. * * * [T]he amounts involved in the allocations of costs are major in size and extremely difficult to make."[24]

8. "[T]he calculation of the unit cost of gas is, and will be an inexact, complex, unsatisfactory, and time consuming process, fraught with controversy."[25]

9. "Another difficulty . . . is presented by the necessity of using estimates of reserves of gas, which can never be precise."[26]

10. "The rate base cost of service method entails consideration of the tax laws. . . . [T]hese difficult and disputatious matters . . . obfuscate and hinder the solution of the problem. . . ."[27]

11. "Thus from each well in the United States every Mcf of gas might have a different price tag."[28]

12. "[L]ow cost producers who must replace diminishing resources would find it increasingly difficult to obtain new leases."[29]

---

[19] *Ibid.*
[20] *Id.* at 543.
[21] *Ibid.*
[22] *Ibid.*
[23] *Ibid.*
[24] *Ibid.*
[25] *Id.* at 544.
[26] *Ibid.*
[27] *Ibid.*
[28] *Ibid.*
[29] *Id.* at 545.

Each and every one of these statements is equally applicable to cost pricing of both on-system production and independent production. Thus the logical grounds for abandoning cost pricing of the latter likewise support abandoning cost pricing of the former.[30]

B. There is no evidence that pipelines and affiliates can find and produce "new" gas more cheaply than independent producers.

As discussed previously, one of the erroneous premises of the Petitioners' brief is that area rates for "new" on-system gas will result in "higher rates" and "unjustified profits." Aside from the answers given earlier to this fallacious charge, it must also be pointed out that the record does not contain any proof that pipelines and affiliates can find gas cheaper than independent producers. Even the examiner said:

> "[P]ipelines [and affiliates] can produce new gas for about the same cost as the independent producers. . . ." R. 10129.

Ignoring this finding, the Petitioners hammer away at their "rate increase" argument. They constantly look backward at the diminishing reserves of old gas — some of it very low in cost and some of it very high — which will be in issue in Phase II, and gloss over the fact that this proceeding is concerned with "new" gas in the search for which all producers start off on an equal footing. The FPC clearly had this backward-looking attitude of Petitioners in mind when it commented on the record evidence concerning the historical costs of on-system gas:

> "This evidence . . . merely reflects the wide divergencies in the periods of time and surrounding circumstances in which pipelines presently with production originally undertook such operations, and by no means indicates that their costs for production from future acquired leases are likely to diverge significantly over

---

[30] As this court well knows, the area rate gas pricing method is very heavily cost oriented. Hence it is not entirely accurate to talk in terms of abandoning cost pricing when describing the shift to area rates. What was abandoned in *Phillips II*, *Permian* and Phase I of RP66-24 was the unworkable, illogical system of individual company cost of service pricing. As the FPC noted below in the case at bar, the cost-oriented "just and reasonable area rates" provide the "anchor" which this court, in *City of Detroit*, felt should be the "point of departure" in moving away from individual company cost of service, or conventional individual rate base pricing. R. 11284.

> a period of time, either from one another or from the average experience of independent producers on similar lease vintages." R. 11285.

The FPC also noted quite significantly that:

> "The present cost-of-service methodology . . . tends to put a premium upon high cost operations (and upon indifference to cost considerations). . . ." R. 11285.

Since the record does not show that new on-system production will be cheaper than new independent production, and since experience indicates that cost of service regulation of new on-system gas prices will probably result in rates for such gas exceeding the area rates, it is clearly in the public interest to abandon the individual company cost of service methodology in pricing new on-system gas.

C. Pipelines and affiliates cannot finance production activities at a lower money cost than independent producers.

One of the principal findings on which the FPC and the examiner diverged involved the crucial issue of the money costs of on-system exploration and production activities. The examiner was persuaded by certain evidence introduced by Petitioners and others that on-system production activities can be financed just like pipeline utility activities. The FPC, on the contrary, was persuaded by the large and overwhelming body of evidence that pipelines and affiliates have no real or apparent advantage in the money markets when it comes to raising capital to finance the risky business of searching for gas.

The FPC's finding on this point is clearly correct and is directly in line, both factually and logically, with its holding in *Permian*, noted earlier, that the risk which controls the capital costs of gas production operations is a risk which is *inherent* in such operations. Obviously, if the risk is inherent in the operation, it cannot be mitigated by ownership of the operation; yet this is precisely what the Petitioners are saying when they argue that pricing on-system "new" gas at area rates will result in excessive returns.

All of the Petitioners' arguments and evidence on this point—including their nonsensical allegations of 20% and 40% equity re-

turns — are based on the theory that allowed rate of return for an individual operation should be tied in with the overall cost of capital to an integrated operation rather than being related to the risk of the individual operation itself. This theory is utterly wrong. The inherent risk in the operation of Pennzoil Producing Company is completely independent of the ownership of this company. This risk is the same whether the stock of this company is owned by the public, by an investment trust or by the parent of a gas transmission company. There can be no lessening of the risk because of association with a pipeline, nor because the capital of the parent had a lower consolidated cost.

Another way to consider the cost of capital problem and the effect of the Petitioners' contentions is to look at the relationship between risk and capital costs in other industries. In real estate, for instance, would it be reasonable to conclude that the risk in the development of a residential subdivision is properly reflected in the interest rate paid on funds borrowed for the subdivision's development, but secured by other collateral? Certainly not, but this is exactly the type of conclusion that the Petitioners unsuccessfully urged upon the FPC below and are presently urging on this court in the case at bar.

Equally crucial to the Petitioners' argument in this regard, is the patently erroneous proposition that production activities can be financed on the basis of a pipeline utility capital structure.[31] The Petitioners argue, in other words, that the highly risky business of searching for gas can be financed with more debt than equity. This argument is, of course, completely at war with the facts of life in the real world in which businessmen must operate, and the evidence in this case is unchallenged in this regard.[32] Bankers, insurance com-

[31] This argument is the *sine qua non* of the spectacular equity returns postulated by the Petitioners. The record shows conclusively, however, that producers cannot arrange the high leverage financing necessary to produce such spectacular returns or any thing approaching such returns. See note 32, *infra*.

[32] Pennzoil Producing Company, recognizing that efforts might be made to apply a pipeline rate of return to producing companies, presented extensive evidence showing that the capital necessary for continued production of a wasting asset such as natural gas requires a higher rate of return than for a non-wasting asset such as pipeline properties. R. 4075-88. Pennzoil Producing Company's comprehensive rate of return evidence was not disputed or denied on the record.

(Continued on next page.)

panies, trustees, and other money managers simply will not lend money to a gas prospector without the protection of a very substantial equity cushion. Indeed, as this court is aware, the FPC in its *Permian* decision determined that gas producers generally have 85% equity and only 15% debt. This low debt ratio confirms the high risk inherent in the production business. If greater equity leverage were feasible, the industry (and the FPC) surely would have taken advantage of it long ago.

In view of the strong affirmance given by the Supreme Court to the FPC's *Permian* decision, it is significant to note the recognition given in such decision to the difference in risk among differing enterprises in a consolidated corporate structure. In *Permian,* the examiner had found that there were,

> "several objections to the staff's inclusion of the integrated companies in determining the comparable earnings standard. First there is little evidence of comparability between the average of the risks and operations of integrated companies — refining, petrochemicals, marketing gasoline — and the risks and operations of

(Note 32 Continued)

The most devastating indictment of the pipeline rate of return as applied to producers was the cash flow statement submitted by Pennzoil Producing Company based on the staff's Initial Brief Appendix "C" showing cash provided and cash required computed by the method used by the FPC in *Phillips* and *Permian.* Pennzoil Producing Company showed that based on the methodology of the *Permian* decision using a 6½% rate of return and regardless of whether there is a low debt-equity ratio (13.9% debt) or a high debt-equity ratio (61% debt) there is a *cash deficiency* of 2.92¢ per Mcf and 4.21¢ per Mcf, respectively. R. 10758. It is clear, as the FPC explained in *Phillips II,* that the funds generated by depreciation, depletion and amortization accruals are not nearly enough to drill new wells to continue production as present wells are depleted:

> "It is clear enough that the industry must continue to find additional reserves of gas and this must come from wells that are drilled even deeper into the earth and some of them off the shore in the Gulf of Mexico. Of course, these deeper wells must be drilled at an increasing cost per foot of depth. It is also true, as Phillips contends, that oil and gas producers must have funds available as their present wells will be depleted to drill new wells and find new reserves. Since these new wells cost a great deal more than the old ones, *the oil and gas producers are being faced with the constant necessity of plowing back into their business a substantial part of their revenue above depreciation and depletion accruals.*
>
> "In view of these practical problems in the gas industry *some allowance must be made in the rate of return to promote the continued exploration for and production of gas."* 24 FPC at 573. (Emphasis supplied.)

finding and producing gas. Second, there is no evidence that integrated companies earn at the same rate for their various operations."[33]

The FPC in *Permian* followed the examiner's lead and also rejected the staff's excessive reliance on integrated companies as a basis for determining the rate of return for gas production alone, stating, "the Shaffner [FPC Staff] study of the returns of integrated producers standing alone fails to make a persuasive showing that the results are the best evidence of the financial needs of the gas operations of the companies involved."[34] The FPC stated further, "We conclude that they [non-integrated producers] are entitled to heavy consideration in the decisional process in the case."[35]

The situation of the pipeline and affiliate producers in the case at bar is directly analogous to the situation of the integrated producers in *Permian*. The FPC acted properly in both instances in relating rate of return to the economic realities of enterprise risk rather than the irrelevant factors of consolidated capital structure and cost. The FPC was affirmed in *Permian* and it should be affirmed in the case at bar.[36]

D. Pipelines and affiliates must have price parity with independent producers or they will be forced to quit the "new" on-system gas business.

As noted earlier,[37] both the FPC and the examiner found that cost of service oriented rates would substantially reduce or virtually eliminate pipelines and affiliates as a factor in the "new" on-system gas business. Ignoring all the evidence supporting this most important finding,

[33] 34 FPC at 347.
[34] 34 FPC at 203.
[35] *Ibid.*
[36] Almost all of the arguments in this section on cost of capital apply with equal force to the Petitioners' allegations concerning tax loss "spillovers." In addition, as the Petitioners say at page 56 of their brief, "It is axiomatic that the tax loss spillovers would tend to increase if increased drilling activities were undertaken. . . ." In other words, if Petitioners could have their way, the more pipelines and affiliates drilled for "new" gas reserves, the more they would be penalized by "flow through" of tax loss "spillovers." As the FPC said below,

"[T]his would tend to discourage the pipelines from entering into or increasing their current rate in the production field." R. 11290.

[37] See page 7 *supra*.

the Petitioners attack it obliquely (1) by saying that pipeline production has "prospered" under cost of service regulation, (2) by saying that any possible disincentive in cost of service prices will be outweighed by the pipelines' desperate need to obtain new gas supplies to protect their "substantial transmission investment", and (3) by saying that area rates will tend to discourage some pipeline producers. All three of these arguments are wrong, as will be shown shortly. First, however, let us look at the evidence that supports the finding by the Commission and the examiner that cost of service oriented rates will greatly inhibit pipeline and affiliate exploration and production activities.

The evidence of the deadening effect of cost of service pricing falls into two principal categories: (1) evidence of the historical effect of this pricing policy, and (2) statements by witnesses concerning the effect that would flow in the future from cost of service pricing for "new" on-system gas.

Concerning the historical effect, the FPC aptly summarized the evidence when it found that:

> "Cost of service pricing of pipeline production . . . has lead in the main to high cost gas *coupled with a continuing reduction in the relative amount of pipeline production.*" R. 11283. (Emphasis supplied.)

Even more directly in point is the Commission's direct response to the challenge to the finding just quoted which was raised by these Petitioners in their Petition for Rehearing below. In denying rehearing, the Commission said:

> "[T]he staff's evidence shows that reserves owned by pipelines and their affiliates attached to their systems have not kept pace in recent years with total reserves in the forty-eight contiguous states, and we think this is very significant from the standpoint of our conclusion here. The staff evidence which tabulates substantially all of the on-system reserves of respondent pipelines and their affiliates amounted in millions of cubic feet to 26,004,457 in 1958, 28,396,480 in 1960 and 25,557,385 in 1965. These figures amount to 10.3 per cent, 10.8 per cent and 8.98 per cent of gas reserves in the forty-eight contiguous states as computed by the American Gas Association Committee on Natural Gas Reserves,

presented in the record by the Pipeline Production Group, and adjusted to exclude Alaskan reserves." R. 11359.

The specific evidence cited by the FPC proves beyond any doubt that pipeline and affiliate on-system reserves have declined substantially both absolutely and in relation to total reserves during the era of cost of service pricing of pipeline production. As the FPC also noted in denying rehearing, the decline is even more dramatic if reserves acquired from independent producers through "Rayne Field" type in-place sales are excluded, as they should be, from total on-system reserves in making this comparison. R. 11359. The evidence on this point shows that pipeline-owned gas reserves are actually only 1% of total gas reserves when one excludes from the pipeline total (1) the Panhandle-Hugoton reserves discovered prior to the construction of the interstate pipelines, (2) the reserves purchased in-place by Tennessee Gas Pipeline Company, Texas Eastern Transmission Corporation and El Paso Natural Gas Company, and (3) the reserves of affiliates such as Pennzoil Producing Company and Cities Service Gas Company which have had their on-system gas prices regulated not on a cost of service basis, but rather on the same basis as independent producers. R. 4073-74. Further evidence to this same effect abounds in the record. On the deleterious effect of cost of service pricing on pipeline production generally, we call the court's particular attention to R. 643-44, 664-67, 685-89, 711-12, 4068-75, and 5969-77.

Looking next to the evidence concerning the likely effect in the future of applying cost of service prices to "new" on-system gas, the evidence is virtually unchallenged to the effect that there is nothing which will reverse the historical pattern just discussed of cost of service virtually eliminating pipelines from the on-system production business. And at this point it is appropriate to emphasize that the only substantial amount of new on-system reserves *discovered* — not purchased in place from independent producers — in recent years has been found by affiliates, principally Pennzoil Producing Company and Cities Service, who have not been regulated on a cost of service basis but rather on the same basis as independent producers. R. 4068-75. This fact not only points the way to the future if the court does not affirm the FPC orders in this case, it also indicates that such little on-

system gas exploration as is currently going on will virtually cease altogther if the FPC's orders are not affirmed at least insofar as they apply to affiliates.

Turning now to the three parts of the Petitioners' oblique attack on the finding that cost of service regulation would almost surely result in there being little or no on-system "new" gas reserves sought for or found, it is clear that the first of the Petitioners' points — that pipeline production has prospered under cost of service pricing — has already been shown to be completely false. On the Petitioners' second point, that pipelines will have to explore for new reserves in order to protect their "substantial transmission investment," the simple answer is that even if pipelines want to explore for "new" on-system gas, they cannot do so without raising capital for the venture and there is not likely to be any capital available where the projected return bears no relationship to the risk involved. Furthermore, the second point boils down to a contention that even though cost of service pricing might be contrary to the public interest because it discourages on-system production, nevertheless it must be utilized because the pipelines as a practical matter will have no choice except to throw good money after bad. Thus stated, the Petitioners' second point is revealed as something less than an appeal to equity, and, indeed, seeks to urge this court to adopt standards which are totally at war with the standards of the Natural Gas Act.

The Petitioners' third oblique response to the finding that cost of service pricing will discourage on-system production is the contention that area rate pricing will have the same discouraging effect on some pipeline producers, "who may not be in the position to assume the risk inherent in exploration activities" (Petitioners' brief at page 31). Obviously, the only on-system exploration and production which will be discouraged by area rate pricing is that which can reasonably be expected to result in costs in excess of those on which area rates are based. How can consumers be harmed by this, especially when the FPC has provided a means for justifying different treatment in special circumstances? The answer is that consumers will not be harmed but rather will be benefited by rate making techniques which put a premium on low cost operations — and the area rate approach is such a technique.

3.

Petitioners' "Rulemaking" and "Cinderella" Arguments Are Wholly Unfounded

A. The "rulemaking" argument.

The Petitioners' argument that the FPC violated the Administrative Procedure Act[38] and Petitioners' due process rights in the course of the proceedings below ultimately rests on the contention that the FPC relied *exclusively* on extra-record evidence of a serious current gas shortage in reaching the result embodied in the orders under review in the case at bar. This is the same thing as saying that there is *no* evidence in the record to support the FPC's findings and conclusions and this is a patently ridiculous contention.

In the preceding sections of this brief, we have demonstrated that the orders here under review are based on findings and conclusions other than those concerning the current gas shortage, and that such findings and conclusions have ample support in the evidence contained in the 11,364 page record of the proceedings below. Clearly, if no evidence of a gas shortage had come to light after the record was closed for evidentiary purposes below, the Petitioners could not have succeeded here with an argument that the orders below were not based on substantial evidence. How, then, can the Petitioners reasonably contend that the order must be set aside because, in addition to the substantial evidence in the record upon which it relied, the FPC took notice of certain non-record facts which unquestionably are of vital significance to gas consumers and to the gas industry?

The gas shortage facts upon which the FPC commented as part of the context of its decision are clearly the type of information of which the FPC is entitled to take official notice.[39] Indeed, these facts

---

[38] 5 U.S.C. §§ 556-57.

[39] § 1.26 (d) of the FPC's Rules of Practice and Procedure states:

> "Official notice may be taken by the Commission and the presiding examiner of such matters as might be judicially noticed by the courts of the United States, or any matters as to which the Commission by reason of its functions is an expert. Any participant shall, on timely request, be afforded an opportunity to show the contrary. Any participant requesting

portend a situation so potentially dangerous for our nation as a whole that the FPC would have been derelict if it had not taken notice of them.

B. The Cinderella case.

As just noted, the Petitioners' "rulemaking" argument ultimately comes down to a contention that there is *no* evidence to support the FPC's orders here being reviewed. The Petitioners' argument based on this court's opinion in *Cinderella* is obviously a variation on this "no evidence" theme, since this court in *Cinderella* clearly recognized that an agency such as the FTC[40] or FPC may overrule all or any part of the examiner's findings and conclusions so long as it considers the examiner's decision and bases its action upon the evidence in the record. As this court said:

> "We do not say that the Commission must find an examiner's findings of fact and conclusions of law 'clearly erroneous' before overturning an initial decision, but we do say that it must consider that decision and the evidence in the record upon which it is based, rather than dismissing the proceedings at the hearing out of hand." Slip Opinion at 10-11.

In *Cinderella* the FTC completely ignored the evidence before the examiner, rejected his findings based on such evidence, considered the matters at issue *de novo* without a hearing, and reached findings and conclusions diametrically opposed to those reached by the examiner. In the case at bar, the FPC carefully considered the evidence adduced

---

the taking of official notice after the conclusion of the hearing must set forth the reasons claimed to justify failure to make the request prior to the close of the hearing."

Also perhaps in point is the following passage from *Continental Can Co.* v. *U.S.*, 272 F.2d 312 (2d Cir. 1959):

> "In reaching their decisions, neither courts nor administrative bodies should ignore the realities of life and disregard common knowledge even though such knowledge may not have achieved a place within the purview of judicial notice." 272 F.2d at 315.

[40] It appears that the FTC rules and regulations contain a provision which was quoted and relied on by this court in *Cinderella* but which has no analog in the FPC's rules and regulations. The provision in question is quoted on page 11 of the *Cinderella* slip opinion and begins with the words:

> "Upon appeal from or review of an initial decision, the Commission *will consider* such parts of the record as are cited. . . ." 16 C.F.R. § 3.54 (a) (1969). (Emphasis added by the court.)

before the examiner, adopted all of his findings and conclusions except those on which it was persuaded to the contrary by the evidence, and fully supported its findings, conclusions and orders with a discussion of the evidence in the record. The *Cinderella* case simply is not in point.

4.

The Gas Shortage

In its decision in the *Southern Louisiana Area Rate Cases* issued March 19, 1970, the Fifth Circuit stated:

> "[T]he circumstances . . . indicate a possibility, indeed perhaps a certainty, that the supply of gas is dangerously low. A serious shortage, in fact, may already be unavoidable because present conditions may render any remedial action ineffective in light of the lag time between remedy and result." Slip Opinion at 52.

In support of this statement, the court cited and discussed at length the 1969 FPC Staff Report on National Gas Supply and Demand which the FPC cited and discussed in the opinions on review in the case at bar. The court found the 1969 Staff Report to be, "a careful, considered document."[41] The court acknowledged that, "We do not know whether the information that has reached us is correct or not,"[42] but the court obviously felt duty bound to take account of the issuance of the 1969 Staff Report and its contents. How, indeed, could the court have done otherwise?

On January 21, 1970, the FPC Bureau of Natural Gas issued a report entitled, "The Gas Supplies of Interstate Natural Gas Pipeline Companies 1968." This 1970 Report is based on annual reports which the FPC requires gas pipelines to file and it fully confirms the potentially disastrous picture painted by the 1969 Staff Report. The 1970 Report shows that in 1968, there was a net decline in gas reserves owned by or dedicated to interstate pipelines. The year-end reserves declined 3.4 trillion cubic feet in 1968 to 198.7 trillion cubic feet, which

---

[41] Slip Opinion at 54.

[42] *Id.* at 58.

was almost identical to the 1966 year-end reserves of 198.4 trillion cubic feet.[43]

Further, the 1970 Report notes ominously that,

> "During [1963 through 1968] production increased by 32.9 per cent, or by about 5.9 per cent compounded annually, and the year-end reserve inventory (after production) increased by 3.5 per cent or by about 0.7 per cent compounded annually."[44]

On the even more critical factor of deliverability, the 1970 Report states that:

> "[A]ssuming continuation of present trends [based on 1963-1968 data] of reserve additions and increased market requirements, . . . a 10 per cent *deficiency* of all companies to meet requirements might occur as early as 1974."[45]

On April 6, 1970, the American Gas Association released figures for 1969 net reserve "additions" which showed that the reserve decline of 1968 accelerated dramatically in 1969. In fact the net decline in year-end reserves in 1969 was more than twice as great as the 1968 decline.[46] Moreover the 1969 decline resulted almost solely from decreased reserve additions rather than from increased consumption.[47]

As the FPC stated in its 1969 Annual Report to Congress:

> "The Natural Gas Act charges the FPC with regulation of the transportation and sale of natural gas in interstate and foreign commerce in the public interest. * * * In the performance of these responsibilities, a major concern of the Commission is to assist the development of conditions which will lead to continuing and adequate supplies of natural gas at reasonable prices."[48]

---

[43] The 1970 Report at 3.
[44] *Ibid.*
[45] *Id.* at 16. (Emphasis supplied.)
[46] The 1968 decline was 5.6 trillion cubic feet; the 1969 decline was 12.2 trillion cubic feet. The 1968 decline noted here is for all national gas reserves (excluding Alaska) while the figures in the text at note call 43 are for interstate reserves only.
[47] Consumption increased in 1969 by 1.3 trillion cubic feet to 20.7 trillion cubic feet. As noted earlier the 1969 reserve decline was 12.2 trillion cubic feet.
[48] House Document No. 91-242, 91st Cong., 2d Sess., at page 43.

The FPC orders here being reviewed by this court were issued with the purpose of promoting the public interest by fulfilling the FPC's obligations in ensuring that gas supplies continue to be available to consumers in adequate quantities and at reasonable prices. The FPC's orders are based upon substantial evidence developed in a very lengthy record. These orders, moreover, were issued, and all proceedings in connection therewith were conducted in full compliance with the procedural requirements of relevant federal statutes and regulations. For these reasons the relief requested by the Petitioners should be denied. Any other action on this review can only contribute to the further deterioration of the already highly dangerous gas supply situation in our nation.

Respectfully submitted,

J. C. Ohet
General Attorney

Pennzoil Producing Company
900 Southwest Tower
Houston, Texas 77002

....

William B. Cassin

Baker, Botts, Shepherd & Coates
1600 Esperson Building
Houston, Texas 77002

Attorneys for
Pennzoil Producing Company

June 15, 1970

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing motion by first-class mail, postage prepaid, to counsel at the addresses listed below:

PARTY	COUNSEL
City of Chicago, *et al*	Charles F. Wheatley, Jr. Esquire Grace Powers Monaco William T. Miller, Esquire Suite 1112—Watergate Office Bldg. 2600 Virginia Avenue, N.W. Washington, D.C. 20037
	Reuben Goldberg, Esquire 1250 Connecticut Avenue, N.W. Washington, D.C. 20036
	George T. Morrow, Esquire Martin, Tate and Morrow Union Planters National Bank Bldg. Memphis, Tennessee 38103
	Max P. Zall, Esquire City Attorney 353 City and County Building Denver, Colorado 80202
	Raymond Simon, Esquire Mathias M. Mattern, Esquire Bernard Rane, Esquire 121 North LaSalle Street Chicago, Illinois 60602
Pipeline Production Group	Raymond N. Shibley, Esquire Patterson, Belknap, Farmer & Shibley 1120 Connecticut Avenue, N.W. Washington, D.C. 20036
	William Warfield Ross, Esquire Wald, Harkrader & Rockefeller 1225 Nineteenth Street, N.W. Washington, D.C. 20036

PARTY	COUNSEL
Mid Louisiana Gas Company	John T. Ketcham, Esquire McGee & Ketcham 1145 Nineteenth Street, N.W. Washington, D.C. 20036
	Grover B. Cobb, Esquire Foy, Cobb, Campbell & Gall P. O. Box 1188 Houston, Texas 77001
	Vernon W. Woods, Esquire P. O. Box 1707 Shreveport, Louisiana 71102
Tennessee Gas Pipeline Company, a Division of Tenneco, Inc.	Harry S. Welch, Esquire Philip D. Endom, Esquire Post Office Box 2511 Houston, Texas 77001
	Harold L. Talisman, Esquire Melvin Richter, Esquire Littman and Werner 1101 Connecticut Avenue, N.W. Washington, D.C. 20036
Consolidated Gas Supply Corporation, *et al*	Norman A. Flaningham, Esquire 425 Thirteenth Street, N.W. Washington, D.C. 20004
Tenneco Oil Company	John E. Watson, Esquire Tenneco Oil Company P. O. Box 2511 Houston, Texas 77001
	Barclay D. McMillen, Esquire 1361 Stratford Drive Kent, Ohio 44240
Federal Power Commission	Peter H. Schiff, Solicitor Federal Power Commission 441 G Street, N.W. Washington, D.C. 20426

Dated at Houston, Harris County, Texas this 15th day of June, 1970.

....
William B. Cassin

Baker, Botts, Shepherd & Coates
1600 Esperson Building
Houston, Texas 77002

BRIEF FOR INTERVENOR
TENNESSEE GAS PIPELINE COMPANY, A DIVISION OF TENNECO INC.

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, et al.,

Petitioner,

v.

FEDERAL POWER COMMISSION,

Respondent,

TENNESSEE GAS PIPELINE COMPANY,
A DIVISION OF TENNECO INC.

Intervenor.

ON PETITION TO REVIEW ORDER
OF THE FEDERAL POWER COMMISSION

Harry S. Welch
Phillip Endom
P.O. Box 2511
Houston, Texas 77001

Melvin Richter
Littman and Werner
1001 Connecticut Ave., N.W.
Washington, D.C. 20036

Counsel for Intervenor,
Tennessee Gas Pipeline Company,
A Division of Tenneco Inc.

June 15, 1970

TABLE OF CONTENTS

CASES CITED

MISCELLANEOUS

*Cases principally relied on are marked with an asterisk.

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ET AL.

Petitioner,

v.

FEDERAL POWER COMMISSION,

Respondent,

TENNESSEE GAS PIPELINE COMPANY,
A DIVISION OF TENNECO INC.

Intervenor.

ON PETITION TO REVIEW ORDER
OF THE FEDERAL POWER COMMISSION

BRIEF FOR INTERVENOR,
TENNESSEE GAS PIPELINE COMPANY,
A DIVISION OF TENNECO INC.

COUNTERSTATEMENT OF ISSUES PRESENTED FOR REVIEW 1/

Tennessee Gas Pipeline Company, A Division of Tenneco Inc. (Tennessee), an intervenor in the above proceedings, believes the issues presented for review to be as follows:

1/ This case has not previously been before the Court.

1. Whether the Federal Power Commission (Commission) properly undertook to price gas produced by producers, other than independent producers, from new gas reserves on the same area rate basis as it prices gas produced by independent producers.

2. Whether the treatment of rate of return and Federal income taxes included in such area rates was proper as extended to pipeline and affiliated producers.

COUNTERSTATEMENT OF THE CASE

Tennessee adopts the Counterstatement of the Case set out in the Brief for the Federal Power Commission.

ARGUMENT

As the Court is undoubtedly aware, the Commission has been engaged for the past several years in developing so-called area prices in connection with its regulation of rates for the independent producers of natural gas. Under this technique, uniform rates are fixed for all sales of gas, subject to the Commission's jurisdiction, produced from a particular area on the basis of group or industry-wide costs. The Commission has already arrived at a determination of such rates for the so-called Permian Basin and South Louisiana areas. See Permian Basin Area Rate Proceeding, 34 F.P.C. 159 (1965), aff'd, 390 U.S. 747 (1968); Southern Louisiana Area Rate Proceeding, 40 F.P.C. 530 (1968), aff'd, 5th Cir. Nos. 27492, et al. (decided March 19, 1970), pending on

applications for rehearing.[2/] Area rate proceedings with regard to the other gas producing areas in the country are pending at various stages before the Commission.

In the order here under review, the Commission has announced its intention to apply the area rates determined for independent producers in the above proceedings to gas produced by other producers, pipelines and their affiliates, from leases acquired after the issuance of the order.[3/] Petitioners seek to attack the Commission's declaration on a variety of grounds, but, as shown below, none of them has any substance or merit.

I.

THE COMMISSION'S UNDERTAKING TO APPLY THE AREA RATES DETERMINED FOR INDEPENDENT PRODUCERS TO GAS PRODUCED BY OTHER PRODUCERS FROM NEW LEASES IS REASONABLE AND PROPER

As its major contention in opposition to the Commission's holding herein, Petitioners (Br. pp. 15-44) argue at length and in detail that the courts have in the past approved the use of individual cost of service with respect to gas produced by producers other than the independent producers. Presumably, Petitioners would have this Court conclude therefore that it is improper for the Commission to apply area rates, instead of individual cost of service, with respect to gas produced by such other producers from new leases.

2/ The Commission's response filed May 28, 1970, to the petitions for rehearing suggested that the case be remanded to it, apparently in order to permit reconsideration of the area rates there fixed in light of the critical gas shortage.

3/ This order was issued in Phase I of the so-called Pipeline Production Proceeding (FPC Docket No. RP66-24) before the Commission. Phase II relates to gas produced by such other producers from leases acquired prior to the issuance of the instant order. No hearings have yet been held or determination made in Phase II.

However, the cases thus relied on by Petitioners fall far short of establishing the conclusion urged by Petitioners. In addition to the fact that the courts in most of Petitioners' cases hold only that the Commission may[4/] -- not that it is required to -- use individual cost of service in costing pipeline produced gas,[5/] Petitioners' contentions ignore the following considerations which, we submit, are critical here:

> (1) in none of the cases cited by Petitioners have the courts held that the Commission is without authority to apply area rates to gas produced by pipeline and affiliated producers such as the Commission has undertaken here;
>
> (2) all the learning to be gleaned from the several cases cited by Petitioners has been reduced to a secondary position in light of the Supreme Court's recent decision in the Permian Basin Area Rate Cases, 390 U.S. 747 (1968); and
>
> (3) the Supreme Court in Permian clearly and explicitly affirmed the Commission's authority to apply area rates or group rates to the production of natural gas.

Petitioners (Br. pp. 35-38) would read the Supreme Court's decision in Permian as sanctioning area rates only for independent producers. But this overlooks the broad sweep of the Supreme Court's holding. The Court there approved group and area pricing generally, including area prices for gas produced by pipeline and affiliated producers, not just area prices for independent producers, as urged by Petitioners. This is apparent from the following language in the Supreme Court's decision:

4/ Emphasis supplied throughout unless otherwise noted.

5/ See, e.g., Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581 (1945) (Pet. Br. pp. 17-18), where the Supreme Court stated (at 601):

> "We do not say that the Commission lacks authority to depart from the rate-base method. We only hold that the Commission is not precluded from using it."

"* * * No more does the Constitution prohibit the determination of rates through group or class proceedings. This Court has repeatedly recognized that legislatures and administrative agencies may calculate rates for a regulated class without first evaluating the separate financial position of each member of the class; it has been thought to be sufficient if the agency has before it representative evidence, ample in quantity to measure with appropriate precision the financial and other requirements of the pertinent parties. * * * (390 U.S. at 769)

*   *   *

"* * * We do not suggest that maximum rates computed for a group or geographical area can never be confiscatory; we hold only that any such rates, determined in conformity with the Natural Gas Act, and intended to 'balanc[e]* * * the investor and the consumer interests,' are constitutionally permissible. * * *" (390 U.S. at 770)

In this regard, it should also be noted that Petitioners' attempt to impugn the use of area rates for gas produced by pipeline and affiliated producers ignores the fact that such area rates are based on costs. To be sure, these costs are group costs, but they are the same type of group costs which the Supreme Court in Permian held could properly be utilized to determine the area rates there involved. Hence, contrary to Petitioners' contention (Br. pp. 20-23, 25-29), applying such area rates to gas produced by pipeline and affiliated producers would not result in a departure from cost without economic justification in violation of holdings such as that in City of Detroit v. F.P.C., 97 U.S. App. D.C. 260, 230 F. 2d 810 (1955), cert. denied, 352 U.S. 829 (1956).

In City of Detroit the Court reversed an attempt by the Commission to shift from a cost to a non-cost basis (i.e., unregulated field price) in fixing rates for pipeline produced gas. Applying area

prices to pipeline and affiliated production as determined by the Commission here involved does not involve a departure from costs. To the contrary, costs are still the basis of these rates, even though they are industry-wide costs instead of costs of a particular company. Moreover, as the Commission pointed out in this regard (R. 11284), the "anchor" which City of Detroit indicated should function as the "point of departure" in moving from the conventional individual cost method, lies in the area rates for independent producers which have been approved as satisfying the just and reasonable standards of the Natural Gas Act.

Nor is there any merit to Petitioners' (Br. pp. 24-25) attempted reliance on the Commission's recent opinion in Continental Oil Company, 39 F.P.C. 1034, 1044-1045 (1968), aff'd sub nom Cities Service Gas Co. v. F.P.C., 10th Cir. No. 151-68 (decided October 16, 1969). While the Commission there claimed that in the past it had applied individual cost of service to pipeline produced gas, its order here recognizes such to be the case and that its holding here represents a change in policy applicable, however, only to the future. Thus, the Commission's order here plainly applies only to gas produced by pipeline and affiliated producers from leases acquired in the future. The Commission's holding here in terms does not apply to "gas taken in a pipeline system -- past, present or future -- from production facilities on leases acquired prior to the date of the decision herein" (R. 11282), a matter "to be considered in Phase II of this proceeding" (R. 11282). Rather, the Commission recognized that "that issue involves

separate problems relating to the historical context under which such production efforts were undertaken which by no means necessarily call for the same resolution to be given to future production from leases acquired after, and in the light of, this decision." (R. 11282)

As is also apparent from the Commission's order herein, one of the Commission's primary reasons for adopting this change of policy and ruling that area rates as determined for independent producers should also be applied to gas produced by pipeline and affiliated producers from new leases, is the need to provide an adequate incentive to such producers, along with the independent producers, to explore for and develop the new gas reserves needed to satisfy the increasing natural gas requirements of the future, a need which has taken on particular importance and urgency in this period of increasing gas shortages.

Thus, the Commission noted in Permian (34 F.P.C. at 185):

> "* * * It is estimated that by 1980 natural gas use, already more than 15 trillion cubic feet a year, will have grown to 25 or more trillion and by the year 2,000 annual use can be expected to exceed 30 trillion.* * *"

These prognostications are buttressed by the estimate of future natural gas requirements published in June 1967 by the Future Requirements Committee under the auspices of the Gas Industry Committee, which is a joint committee of the American Gas Association, the American Petroleum Institute and the Independent Natural Gas Association of America (R. 735). In this report which was prepared in cooperation with the Denver Research Institute of the University of Denver, the Committee estimated the natural gas annual requirements of the United States as follows (see R. 735):

Year	Annual Requirements (Trillion Cubic Feet) At 14.73 psia and 60° F.
1966	17.8
1967	18.8
1968	19.7
1969	20.7
1970	21.5
1975	25.5
1980	28.6
1985	32.0
1990	36.0

Further, according to the above Report, the cumulative natural gas requirements between 1968 and 1975 will be 218 trillion cubic feet and the cumulative requirements between 1966 and 1990 will be 680 trillion cubic feet (R. 736). This is to be compared with the estimated proven recoverable natural gas reserves of 289.3 trillion cubic feet nationally as of the end of 1965 (see F.P.C. 1967 Annual Report to Congress, p. 39).

The individual cost of service method has failed to provide the requisite incentive to pipeline and affiliated producers to explore for and develop new gas supplies. As the Commission pointed out (R. 11283-11284):

> "Cost-of-service pricing of pipeline production, except with respect to some old production facilities acquired at very low cost before the development of the natural gas industry as we know it, has led in the main to high-cost gas coupled with a continuing reduction in the relative amount of pipeline production. If pipelines, by moving to an area rate technique, can be encouraged to increase their activity in the search for and production of gas without increasing the overall cost of the gas to the consuming public, this certainly should be encouraged.
>
> * * *
>
> "We arrive at this conclusion at a time when there are indications of a shortage of gas and a threat of a greater shortage in the future.* * *"

Not only had the Commission in Permian similarly recognized the desirability of providing producers with an incentive to explore for and develop the gas supplies needed to meet future requirements, but it made such incentive the foundation of a dual-area price system which it there adopted for independent producers. As stated by the Commission in Permian (34 F.P.C. at 184, 186):

> "* * * the emergence of directionality, i.e., the ability of producers to direct their drilling activities toward either oil or gas brings into being for the first time an opportunity for price to play a significant role in increasing the supply of gas-well gas available to the interstate market. We have reflected this fact in the system of ceiling prices which we are adopting because, in our opinion, the true benefits of directionality can be best achieved through a two-price system which, though based on costs, by its very nature provides a special inducement for exploration for gas-well gas. Such a system should permit price to play its full role in eliciting needed gas supplies.* * *
>
> * * *
>
> "* * * Looking to the future we are establishing a pricing system that will encourage the industry to expand and perfect its ability to drill directionally so that revenues from gas consumers can increasingly be devoted to finding additional gas reserves."

For its part, the Supreme Court explicitly noted the Commission's rationale in this regard and specifically approved it. Thus, as summarized by the Supreme Court in its Permian decision (390 U.S. at 759-760):

> "The rate structure devised by the Commission for the Permian Basin includes two area maximum prices. The Commission provided one area maximum price for natural gas produced from gas wells and dedicated to interstate commerce after January 1, 1961 [fn. omitted]. It created a second, and lower, area maximum price for all other natural gas produced in the Permian Basin. The Commission reasoned that it may employ price functionally, as a tool to encourage discovery and production of appropriate supplies of natural

> gas. It found that price could serve as a meaningful incentive to exploration and production only for gas-well gas committed to interstate commerce since 1960; * * *. The Commission expected that its adoption of separate maximum prices would both provide a suitable incentive to exploration and prevent excessive producer profits."

And in approving this dual-price area rate system, the Supreme Court commented:

> "* * * The Commission reasoned that a higher maximum rate for gas-well gas dedicated to interstate commerce after the approximate moment at which a separate search became widely possible would provide an effective incentive. [fn. omitted] * * * (390 U.S. at 797)
>
> * * *
>
> "The Commission's responsibilities include the protection of future, as well as present, consumer interests. It has here found, on the basis of substantial evidence, that a two-price rate structure will both provide a useful incentive to exploration and prevent excessive producer profits. In these circumstances, there is no objection under the Natural Gas Act to the price differentials required by the Commission." (390 U.S. at 798)

In this regard, Petitioners (Br. pp. 29-35) further contend that the record here does not support the use of area prices for pipeline-produced gas and that the Commission relied on extra-record materials, particularly with reference to the developing gas shortage, in order to reach its result -- all in violation of the requirements relating to adjudicatory proceedings (see also Br. pp. 57-69). But much of Petitioners' discussion in this connection, as well as their references to the evidence herein, focuses upon the evidence submitted by them and gives no weight to the opposing evidence which was submitted by other parties, and upon which the Commission based its conclusion. In other words, Petitioners here are seeking to have the Court weigh the evidence

independently, whereas established doctrine requires the courts to affirm the Commission's findings when supported by requisite evidence. See, e.g., Section 19(b) of the Natural Gas Act.

The fact is, moreover, that the Commission's findings with which Petitioners seek to take issue are based on evidence in the record and facts which are within the general knowledge of the Commission or of which the Commission may properly take notice. Cf. Alabama-Tennessee Natural Gas Co. v. F.P.C., 359 F. 2d 318, 339 (5th Cir., 1966), cert. denied, 385 U.S. 847 (1966); F.T.C. v. Cement Institute, 333 U.S. 683, 700-703 (1948).

Petitioners' (Br. p. 63) complaint in this regard is addressed particularly to what they characterize as the "two key facts" underlying the Commission's holding. But their formulation of one of these allegedly "key facts", i.e., that "area rate pricing will provide incentive for exploration and development sufficient to remedy the gas supply shortage," grossly overstates the Commission's actual position. In dealing with the Petitioners' comparable contention in its order denying rehearing, the Commission stated (R. 11360):

> "While we cannot find with certainty that area rate costing of pipeline production will cause greater production, we expect that such a pre-determined cost allowance for pipeline producers will induce exploration and development because of the assurance to pipelines that they will stand to gain as a result of superior judgment and efficiency and that any additional gains would not automatically be withdrawn to satisfy a cost formula. Moreover, since the order only applies to production from future acquired leases, 'additional' returns, if any, would be earned only to the extent that pipelines were in fact stimulated to explore for and develop new reserves."

In contrast, as the Commission further found (R. 11283-11284), the individual cost of service method has failed as an incentive to pipelines to undertake exploration and development of new reserves.

As to the other "key fact," i.e., that the nation is being confronted by an increasingly critical shortage of gas which makes it necessary to take affirmative steps to encourage exploration and development of new gas, a complete answer is contained in the extensive discussion of that threatened shortage in the Fifth Circuit's opinion in Southern Louisiana Area Rate Cases, 5th Cir. Nos. 27492, et al. (decided March 19, 1970). In view of its pertinence here, we quote at length from that decision (slip opinion pp. 52-56):

> "* * * the circumstances that have developed since [the Commission's] decision indicate a possibility, indeed perhaps a certainty, that the supply of gas is dangerously low. A serious shortage, in fact, may already be unavoidable because present conditions may render any remedial action ineffective in light of the lag time between remedy and result. Thus the producers point out to us that the FP [finding to production] ratio, for the first time since World War II, shows that findings have declined below production. In other words, the gas industry in 1968 took more gas out of the ground than it discovered. Together with a growing production curve, this fact is alarming, especially since it is likely that the FP ratio will remain below 1.0 for the foreseeable future. 96/ The producers also contend that the RP [reserves to production] ratio is dangerously low, and despite the frequency with which this argument has been effectively categorized as a 'cry of wolf,' [fn. 97 omitted], we are concerned about it here. A majority of the Commissioners on the FPC have alluded in public speeches

---

"96/ See FPC, Staff Report on National Gas Supply and Demand 11 (1969) (projecting FP ratio as declining steadily from 0.92 in 1969 to 0.73 in 1975)."

to the seriousness of the supply problem. 98/ And an even more persuasive indication of the immediacy of the problem is the recent FPC Staff Report on National Gas Supply and Demand, issued October 1, 1969, which concludes that 'only a few years remain before demand will outrun supply.' 99/

"The Staff Report is, at least from appearances, a careful, considered document. The record in this case does disclose instances in which Staff has been egregiously, in error [fn. 100 omitted], but we think there is something to its supply and demand report. The report is based upon quantitative projections of demand and several indicia of supply -- precisely the kind of 'assessment of consequences' that we find lacking in the Commission's decision here. Demands for Southern Louisiana's gas, according to the Staff report, will be double its 1969 level in 1975. The FP ratio will remain below 1.0. The RP ratio will decline below 11 by 1973 even under the best of circumstances, and there is nothing that can be done at this time to maintain the ratio at its present level. The report further argues, and argues persuasively, that the inevitable decline in the RP ratio will probably cause regional supply deficiencies to come into existence as early as 1973. 101/ And aside from probable

---

" 98/ See Address by Chairman White, A Regulator Looks at the Electric and Gas Industries with a Sidelong Glance at Investment Analysis, before the Financial Analysts Federation, May 16, 1969; Address by Commissioner O'Connor, Prospects for Future Gas Supplies, before the National Ass'n of Regulatory Utility Commissioners, October 7, 1969; Address by Commissioner Brooke, before the Independent Natural Gas Ass'n of America, September 9, 1969; Address by Commissioner Bagge, The FPC and Area Pricing: The Need for Re-examination, before the Gas Industry Seminar at Oklahoma State University, May 13, 1969.

We take judicial notice of the concerns these speeches express. See C. McCormick, Evidence §328 at 704 (1954). (We do not, of course, take judicial notice of the specific facts they state for the purpose of resolving contested issues. Id.)"

" 99/ Staff Report at 1."

"101/ A critical ratio will ultimately be reached in each area below which the RP ratio cannot be decreased, meaning that at that point production cannot be increased without reserve additions, according to the Staff Report. But reserve levels at any given time

short-term deficiences that cannot be prevented, Staff concludes that '[a] major new government-industry program is needed immediately to insure the continued growth of natural gas service during the next decade.' 102/

"The projection in the Report focuses on the next five years, and Staff announces its intention to update it at five-year intervals, but some predictions are made for longer terms. It is not too early to begin considering the effect of present gas use on our resources in the far future. 103/ The Staff Report, if it is correct, shows that unavoidable gas supply problems in the near future,

---

"101/ (continued from previous page) are determined by previous levels of exploration, and there is a lag before new exploration results in addition of usable reserves. Staff has calculated the critical RP ratio for Southern Louisiana at approximately 8. It has projected the future of the RP ratio and determined that the critical level will be reached about 1973 or 1974 under a 'business as usual' regulatory program. At that time production, having kept up with demand, will not be capable of being increased, and deficiencies will come about which production from other areas will not be able to pick up because of lack of delivery lines and because they will be approaching the critical ratio. See Staff Report at 14-17."

"102/ Staff Report at 4."

"103/ The supply of natural gas is, of course, ultimately limited not by exploration but by the amount of recoverable reserves. The Potential Gas Committee, a group of experts from all segments of the gas industry, has recently estimated the total recoverable reserves in and offshore to the United States and Alaska at 1,227 trillion cubic feet, divided into probable supply, possible supply, and speculative supply. Consumption in 1968 was 19 trillion cubic feet. Address by Commissioner O'Connor, supra note 98. In other words, production for something over sixty years would exhaust this estimated supply even at present levels. The situation is aggravated by (1) growing demand and (2) increasing difficulty of finding reserves as one goes from probable to speculative supply areas. See Terry, Future Life of the Natural Gas Industry, in Economics of the Gas Industry 275 (Southwest Legal Foundation ed. 1962). Of course

the middle future, and the far future are not only possible, but probable. 104/ This prospect needs only to be considered against the huge and growing importance of natural gas in this nation's energy mix."

It is to be noted that the Fifth Circuit's concern with the threatening gas shortage is based on extra-record materials, even though the Commission proceeding there under review was an adjudicatory proceeding, as is the instant case. Interestingly enough, in addition, Petitioners themselves (Br. p. 64, fn. 129), in trying to undermine the AGA statistics referred to by the Commission here (R. 11284), rely on the F.P.C. Staff Report and the speech of former Chairman White, also cited in this connection by the Fifth Circuit. Inasmuch as the evidence of a growing gas shortage has been accumulating apace, and it is a matter of common knowledge that such shortage may well be even more serious than the Commission envisioned when it issued its order here under review, acceptance of Petitioners' arguments in this regard would serve only to postpone the day when the Commission may undertake to encourage pipeline and affiliated producers, through area rates, to explore and develop needed new gas supplies.

(continued from previous page)

"103/ supply from other countries, pipelined in or brought in as liquid (LNG), synthetic gas and other sources, could have an impact on this problem. Staff Report at 47-76. Farsighted gas regulation, however, would take into account the rational development of this depletable supply, perhaps even to the extent of having that development influence present area rates. See note 121 infra."

"104/ Staff Report at 19 (graph showing supply, demand, and deficiency projections into the late 1980's)."

II.

THE COMMISSION'S TREATMENT OF RATE OF RETURN
AND INCOME TAXES IS PROPER

As part of its effort to upset the Commission's order, Petitioners further urge that the Commission's determination that to apply the area rates as determined for independent producers to gas produced by other producers will result in an excessive rate of return and an unwarranted failure to require the passing on of certain tax benefits to the consumers. As shown below, these arguments likewise have neither substance nor merit.

A. Rate of Return

As just mentioned, Petitioners (Br. pp. 45-50) claim that the Commission erred in deciding to apply the area rates determined for for independent producers to other producers because, according to Petitioners, to do so results in allowing excessive rates of return to such other producers. In Petitioners' words (Br. p. 46):

> "* * * because of the recognized differences in capital structure between the pipeline producer and the independent producer an equal overall return would provide much larger returns on equity ('profit') to the pipeline producer. [fn. omitted.] Therefore any method of regulation which permits the pipeline producer an overall rate of return equal to that of the independent producer will put the pipeline in a position of super-parity vis-a-vis the independent producers."

The difficulty with this argument is that it overlooks the fact that past financing by pipelines has been devoted overwhelmingly to the financing of pipeline ventures, not producing ventures, and hence does not support the inference that pipelines can finance future producing ventures less expensively than independent producers (R. 4063;

see also R. 11286). Inasmuch as leases cannot be acquired or developed in the future with already invested dollars, it is apparent that in calculating the cost of capital for such future acquisitions and development, it is necessary to use the estimated future cost of debt and equity.

In this regard, it should be noted that the evidence shows that it is more likely that independent producers will be able to finance future producing ventures more cheaply than pipeline producers. Independent producers have long specialized in the production business and have built up large, experienced organizations to perform this function. Accordingly, since the financial community may very well regard independent producers as having a greater know-how than pipeline producers with regard to production business, independent producers may have a psychological advantage over pipeline producers in financing producing ventures. (R. 4063).

Furthermore, since independent producers have proportionately less debt presently outstanding than pipeline producers, they may, in fact, be in a better position to raise new debt capital to finance future producing ventures (R. 4063). Based on their record in issuing new debt securities, independent producers apparently are already raising new debt capital on better terms than pipeline producers (R. 6126).

Moreover, even if the capital costs of pipelines were lower than those of independent producers by virtue of the pipeline producers having higher debt-equity ratios, the Commission's holding here would nevertheless be proper. Since return is only one of several components

used in fixing area rates, focusing upon this particular cost component as excessive and disregarding the cost components which may, in the case of pipeline production, be higher than the amount allowed therefor in determining independent producer area rates, would be clearly unjustified and discriminatory (R. 3979). Indeed, to give effect to such an argument could only serve to penalize the more efficient procurers of capital and thereby be "basically inconsistent with a major premise of area pricing, that low-cost producers should reap the reward of their luck or efficiency" (R. 11287; see also R. 3982-3983). As the Commission stated in its decision in Permian (34 F.P.C. at 179):

> "A uniform area pricing system is adapted to the economics of the natural gas industry. The producer who finds large reserves will achieve greater profits than the producer whose exploration efforts result in dry holes or marginal wells. Likewise, the producer whose enterprise is conducted with efficiency and economy will make more money than the producer who runs his business poorly. * * * True, individual returns will vary greatly, but this is as it should be, provided that profits in the aggregate are at a reasonable level."

On the other hand, since the area rates for independent producers would have to meet the statutory standard of justness and reasonableness, applying such area rates to pipeline production would provide an incentive to explore for and develop new gas reserves, while at the same time insulating the consumers from inordinate risks involved in exploration and development (see R. 11285, fn. 9, 11287). See also Permian, 34 F.P.C. at 179, where the Commission stated:

> "There is a strong incentive in area pricing to prudence and economy which does not exist in individual company cost-plus pricing.* * *"

If, for example, a pipeline is a high-cost producer, the company itself will bear the costs above the applicable area rate, whereas under cost of service the burden of these higher costs would be shifted to the consumers. This redounds to the benefit of the consumers, for it is immaterial to them who conducts the exploration and development for the needed additional gas supplies -- be it pipeline producer, affiliated producer, or independent producer -- so long as the additional gas supplies are forthcoming when needed.

In this regard it should be noted that, as shown by the evidence herein, exploration and development of natural gas reserves by pipeline producers is virtually indistinguishable from such activities by independent producers. Not only do the success ratios of pipeline producers with regard to exploratory and developmental wells closely parallel those of independent producers (R. 658-660, 681-682, 5825, 5827), but their drilling and equipment costs are very close to the comparable costs of independent producers (R. 673, 683, 5858, 5906). In addition, the record establishes that the technology and methodology utilized by pipeline producers in the exploration and development of gas reserves are identical to those of independent producers (R. 644-648).

In addition, many of the production activities of pipeline producers have been undertaken as a joint enterprise with other producers, in particular with independent producers (see R. 647-648, 670-672, 920, 941, 5900). The existence of substantial joint ownership of producing properties among the various kinds of producers serves to emphasize

that the problems and risks associated with the exploration for and development of new gas reserves are identical, whether undertaken by pipeline producer, affiliated producer, or independent producer (see e.g., R. 670-671).

In view of this basic identity in production activities regardless of by whom they are carried on, the considerations which persuaded the Courts to approve the Commission's providing an incentive in the form of area rates to independent producers to explore and develop new gas reserves, similarly require approval of the Commission's providing the same encouragement and incentive to pipeline producers. Indeed, should the pipeline producers and independent producers receive dissimilar rate treatment with respect to new gas reserves, the class of producer receiving the lesser incentive will, as the Commission pointed out (R. 11286-11287), be at a disadvantage in the competition for funds (see R. 920, 948-949); and to this extent, fulfillment of the objectives of encouraging exploration and development of new gas reserves adequate to satisfy future anticipated requirements will be frustrated. As stated by the Commission (R. 11287), if pipeline producers were to be treated differently from independent producers, it would "virtually [be] guaranteed to discourage pipelines from entering the production area to any large degree."

B. Federal Income Taxes

Petitioners (Br. pp. 51-56) also attack the Commission's allowance of area rates for pipeline producers because, according

to Petitioners (Br. p. 51):

> "[it] effectively undermines the longstanding, court-sanctioned policy that the consumer should pay only the actual taxes incurred by the pipeline.97/ The adoption of area rates for pipelines prevents the tax credits emanating from pipeline production from being used to reduce the taxes allowed in cost of service of the transmission operation, directly contrary to the holding in El Paso, supra, (n. 97) that any actual savings in taxes must be passed to the consuming public. [fn. omitted.]"

"97/ El Paso Natural Gas Co. v. FPC, 281 F. 2d 567 (5th Cir. 1960), cert. denied, 366 U.S. 912 (1961)."

By way of background, it should be noted first, that there is no component for income taxes nor reduction for tax credits included in the area rates determined by the Commission for the Permian Basin (34 F.P.C. at 206-207) and Southern Louisiana (40 F.P.C. at 581-586) for the reason that the industry-wide figures used in both of these cases failed to establish either tax liabilities to be allowed or net tax benefits to be credited in fixing the area rates for independent producers there involved.

Such also is the case with regard to other producers; the record here does not establish any tax liability or net tax credit for such producers on an industry-wide basis. Indeed, at the close of the hearing, the parties joined in a stipulation that "an actual positive or negative tax liability can not be determined from the data available in this record." (R. 5420). Since the record does not show any net tax benefits for crediting as proposed by Petitioners,

on the industry-wide basis used in determining area rates, the absence of any such provision in the area rates applied to pipeline producers is wholly consistent with -- not violative of -- the alleged "actual taxes payable" principle stressed by Petitioners.

Petitioners (Br. pp. 55-56, fn. 105), would brush aside these industry-wide figures and go instead to the alleged tax experience of individual pipeline producers on a separate basis. But the use of separate data pertaining to individual companies is inconsistent with the basic concept of area rates which are based on industry-wide figures -- not those of any particular company -- and are designed to price the product, not the producer (34 F.P.C. at 179):

> "Basic to [the] determination [of area rates] is the fact that objective cost standards for fixing just and reasonable rates for producer sales can best be developed by examining overall producer experience. An individual producer may find only dry holes or marginal wells or his search for gas may result in finding a huge new gas field. A price fixed by his individual cost experience could thus either be too high for consumers in relation to other available supplies or too low to be fair to the producer, considering his risks. However, on a group basis, costs and rates can be developed which will be fair to all concerned. A uniform ceiling price for the area will provide a fair relationship between the aggregate price the consumer pays and the aggregate costs that the producers incur."

Moreover, since the income tax picture varies from pipeline producer to pipeline producer, just as it does among independent producers, there is no more reason for according individualized income tax treatment for pipeline producers than there is for

independent producers. This is particularly so (1) in light of the obvious incongruity of using an individual income tax computation for a pipeline producer where the rest of the components used to determine the allowance for gas produced by it are fixed on an industry-wide basis, and (2) in the absence of a specific determination that the average costs of pipeline producers with respect to other components included in the rates allowed for pipeline produced gas are not above the industry average (See R. 3986).

Furthermore, under the area rates as determined by the Commission for independent producers, independent producers are free to use any tax benefits which may be generated by drilling programs in excess of the taxable income generated by production functions to reduce its costs associated with the production of gas. In contrast, under Petitioners' argument, the pipeline producers having such tax benefits would be unable to make such use of them since Petitioners would require that such tax benefits be passed on by being applied to reduce the pipelines' cost of service for the transmission phase of its business (R. 4065).

Such a disparate treatment would have serious results wholly inconsistent with the purpose of applying area rates to pipeline produced gas. Any tax deduction spillover which a pipeline may have on its gas production would come about either because it is losing money on its gas production or because it has a relatively active exploration and development program resulting in high

exploration and development costs and high-expensed, intangible drilling costs. In the first situation, it would be unreasonable to reduce the rates allowed the pipeline producer since he is obviously producing at a loss and the result of the rate reduction would be to increase his losses. In the second case, a reduced rate to reflect the tax loss spillover would penalize the pipeline producer for engaging in above-average exploratory efforts. Since it would mean that those pipelines with the most exploration activities would be permitted the lowest rates while those with the least exploration activities would enjoy the highest rates, such a "nonsensical" result (R. 3987) obviously would serve as a deterrent upon pipelines' undertaking to explore for and develop new gas reserves and thereby would operate to frustrate a major purpose for applying area rates to pipeline production (see R. 4065).

CONCLUSION

For the foregoing reasons, it is respectfully submitted that the Commission's order should be affirmed.

Respectfully submitted,

Harry S. Welch
Phillip Endom
P. O. Box 2511
Houston, Texas 77001

Melvin Richter
Littman and Werner
1001 Connecticut Ave., N.W.
Washington, D.C. 20036

Counsel for Intervenor,
Tennessee Gas Pipeline Company,
A Division of Tenneco Inc.

Dated June 15, 1970

CERTIFICATE OF SERVICE

I, Melvin Richter, hereby certify that the foregoing document was served this 15th day of June, 1970 by mailing true copies thereof, postage prepaid, to the following persons at the addresses shown below:

Gordon Gooch, General Counsel
Federal Power Commission
441 G Street, N. W.
Washington, D. C. 20426

Peter H. Schiff, Solicitor
Federal Power Commission
441 G Street, N. W.
Washington, D. C. 20426

Counsel for Federal Power Commission

John C. Ohrt, Esq.
General Attorney
Pennzoil Producing Company
1900 Southwest Tower
Houston, Texas 77002

William B. Cassin, Esq.
Baker, Botts, Shepherd & Coates
1600 Esperson Building
Houston, Texas 77002

Counsel for Pennzoil Producing Co.

Raymond N. Shibley, Esq.
Patterson, Belknap,
Farmer & Shibley
1120 Connecticut Ave., N. W.
Washington, D. C. 20036

Wm. Warfield Ross, Esq.
Wald, Harkrader & Rockefeller
1225 - 19th Street, N. W.
Washington, D. C. 20036

Counsel for Pipeline Production Group

Charles F. Wheatley, Jr., Esq.
Grace Powers Monaco
William T. Miller, Esq.
Suite 1112 - Watergate Office Bldg.
2600 Virginia Avenue, N. W.
Washington, D. C. 20037

Reuben Goldberg, Esq.
1250 Connecticut Avenue, N. W.
Washington, D. C. 20036

George E. Morrow, Esq.
Martin, Tate & Morrow
Union Planters National Bank Bldg.
Memphis, Tennessee 38103

Max P. Zall, Esq.
City Attorney
353 City and County Building
Denver, Colorado 80202

Raymond Simon, Esq.
Mathias M. Mattern, Esq.
Bernard Rane, Esq.
121 North LaSalle Street
Chicago, Illinois 60602

Counsel for City of Chicago, et al.

Robert L. Norris, Jr., Esq.
Humble Gas Transmission Company
P. O. Box 2180
Houston, Texas 77001

Counsel for Humble Gas Transmission

Norman A. Flaningam, Esq.
425 - 13th Street, N. W.
Washington, D. C. 20004

Counsel for Consolidated Gas Supply Corp., et al.

John E. Watson, Esq.
Tenneco Oil Company
P. O. Box 2511
Houston, Texas 77001

Barclay D. McMillen, Esq.
1361 Stratford Drive
Kent, Ohio 44240

Counsel for Tenneco Oil Co.

Melvin Richter
Attorney for
Tennessee Gas Pipeline Company,
A Division of Tenneco Inc.

JOINT BRIEF FOR INTERVENORS
CONSOLIDATED GAS SUPPLY CORPORATION,
IROQUOIS GAS CORPORATION, PENNSYLVANIA
GAS COMPANY AND UNITED NATURAL GAS COMPANY

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23,740

CITY OF CHICAGO, ILLINOIS; CITY AND COUNTY OF DENVER, COLORADO; MEMPHIS LIGHT, GAS AND WATER DIVISION, MEMPHIS, TENNESSEE; AND THE AMERICAN PUBLIC GAS ASSOCIATION,

Petitioners,

v.

FEDERAL POWER COMMISSION,

Respondent,

L. R. Reif
10 Lafayette Square
Buffalo, New York 14203

Richard M. Di Valerio
308 Seneca Street
Oil City, Pennsylvania 16301

ATTORNEYS for IROQUOIS GAS CORPORATION, PENNSYLVANIA GAS COMPANY, UNITED NATURAL GAS COMPANY, Subsidiaries of NATIONAL FUEL GAS COMPANY

David E. Weatherwax
445 West Main Street
Clarksburg, West Virginia 26301

Henry P. Sullivan
4 Gateway Center
Pittsburgh, Pennsylvania 15222

Norman A. Flaningam
Charles R. Brown
744 Pennsylvania Building
Washington, D. C. 20004

ATTORNEYS for CONSOLIDATED GAS SUPPLY CORPORATION

June 15, 1970

TABLE OF CONTENTS

TABLE OF CASES

COUNTERSTATEMENT OF QUESTION PRESENTED

In the opinion of Joint Intervenors, the sole question presented in this case is:

Did the Federal Power Commission err in adopting a policy of henceforth regulating the price of gas produced from new leases by pipeline companies (or their affiliates) on the same basis as gas produced by independent producers?

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23,740

CITY OF CHICAGO, ILLINOIS; CITY AND COUNTY OF DENVER, COLORADO; MEMPHIS LIGHT, GAS AND WATER DIVISION, MEMPHIS, TENNESSEE; AND THE AMERICAN PUBLIC GAS ASSOCIATION,

Petitioners

v.

FEDERAL POWER COMMISSION,

Respondent

JOINT BRIEF FOR INTERVENORS
CONSOLIDATED GAS SUPPLY CORPORATION,
IROQUOIS GAS CORPORATION, PENNSYLVANIA
GAS COMPANY AND UNITED NATURAL GAS COMPANY

COUNTERSTATEMENT OF THE CASE

This case is before the Court upon a petition under Section 19(b) of the Natural Gas Act (Act)[1/] filed by the City of Chicago, Illinois; City and County of Denver, Colorado; Memphis Light, Gas and Water Division, Memphis, Tennessee; and the American

1/ Act of June 21, 1938, C. 556, Section 19(b); 52 Stat. 821, 831; 15 USC § 717, 717r(b).

Public Gas Association seeking review of an Order 2/ of the Federal Power Commission (Commission).

The Order in question promulgates the policy the Commission intends to employ in determining the allowance to be permitted in future individual pipeline company rate cases for gas produced by interstate pipelines (or their affiliates) from leases acquired subsequent to October 7, 1969.

In the interests of brevity, Joint Intervenors hereby adopt the Counterstatement of the Case contained in the Brief for the Federal Power Commission, as supplemented by the following description of Joint Intervenors' operations and interest in this proceeding.

Consolidated Gas Supply Corporation (Supply Company), a respondent below, is the principal supply arm of the Consolidated Natural Gas System, 3/ one of the largest gas utility systems in the United States. The System serves approximately 1,400,000 customers at retail and another 800,000 customers through wholesale sales to other utilities. Revenues from the local distribution

2/ Opinion No. 568 and Order issued October 7, 1969, entitled Pipeline Production Area Rate Proceeding (Phase I), Docket No. RP66-24 (R. 11292-11293); as modified on rehearing by Opinion No. 568-A, issued December 5, 1969 (R. 11357-11364).

3/ In addition to Supply Company, the Consolidated Natural Gas System is comprised of the parent company, Consolidated Natural Gas Company; the System service company, Consolidated Natural Gas Service Company, Inc.; and five operating companies: The East Ohio Gas Company; Lake Shore Pipe Line Co.; The Peoples Natural Gas Company; The River Gas Company and West Ohio Gas Company.

of natural gas constitute approximately 80% of the System's total revenues (R. 914).

Although Supply Company has production operations in the Appalachian and Southern Louisiana Areas, it purchases the bulk of its supplies from three interstate pipelines that either produce gas directly or through affiliated companies.[4/] Substantial additional volumes of gas are obtained directly from independent producers in the Appalachian and Southern Louisiana Areas.

Iroquois Gas Corporation, Pennsylvania Gas Company and United Natural Gas Company, also respondents below, are members of the National Fuel System, another of the Nation's major gas utility systems serving more than 600,000 customers at retail in northwestern Pennsylvania, western New York and eastern Ohio. The National Fuel System produces substantial quantities of gas in the Appalachian Area and also makes purchases directly from independent producers operating in that area. And, like Supply Company, it purchases most of its supplies from five interstate pipeline companies.

The Consolidated and National Fuel Systems are first and foremost distributors of natural gas. The paramount interests of these gas distribution systems, as large-volume purchasers from interstate pipelines, stem from their need to obtain from

4/ Texas Eastern Transmission Corporation, Texas Gas Transmission Corporation and Tennessee Gas Pipeline Company, a Division of Tenneco, Inc. The System also purchases from other pipeline producers through The East Ohio Gas Company and West Ohio Gas Company

their pipeline suppliers the volumes of new supplies necessary to satisfy the rapidly-increasing demands of their customers -- and to be assured that these supplies will become available at reasonable prices.

SUMMARY OF ARGUMENT

1. The Commission found that it is in the public interest to promulgate a new policy for valuing natural gas produced by pipelines (and their affiliates) from leases acquired after the date of its Order. The Commission has announced its intention henceforth to regulate gas produced by pipelines on the same basis as it regulates gas sold in interstate commerce by independent producers -- i.e., the area-rate method. The new policy is designed to encourage pipelines to engage in more aggressive exploration and production programs, and, simultaneously, to insure the consuming public that it will pay no more than the just and reasonable area rate -- which the pipeline would be required to pay if it had no company-owned production. Applicable precedent clearly permits the Commission to depart from the individual company cost-of-service method previously employed and adopt the Supreme Court's sanctioned area-pricing method for new pipeline production. The Commission's Opinion has a rational basis in law, is supported by substantial evidence of record and should be accepted.

2. In shifting to area pricing for new gas to be produced by pipelines, the Commission properly refused to depart from the basic concepts of area-rate regulation by modifying the area rates applicable to pipeline-owned production to reflect the individualized return requirements or the Federal income taxes actually paid during the applicable test period by the pipeline company involved in any future rate case. Such a policy would have been alien to the fundamental concepts of area ratemaking, which looks to average, industry-wide costs in determining the ceiling price for new gas.

All parties to the proceeding below (including Petitioners) stipulated that, in the aggregate, ". . . an actual positive or negative tax liability cannot be determined from the data available in this record" (R. 5420). In these circumstances, there is no more reason to determine separately the Federal income tax allowance applicable to new pipeline production than there is to individualize the income tax treatment for independent producers.

The record also fails to show any basis for Petitioners' contention that pipelines will be able to finance their future production operations less expensively than independent producers. Assuming arguendo that pipelines have had relatively lower capital costs than the independents by virtue of their high debt/equity ratios, the end result of the Commission's policy cannot be said to be unreasonable. Rate of return is, after all, only one of the many components used by the Commission in fixing area rates. And, the record discloses that -- at least with respect to past

production operations -- pipeline producers, on the average have experienced higher than industry-average costs in several of the other components (R. 3980). In these circumstances, it is unreasonable and unfair to select arbitrarily the return and Federal income tax components for individualized ratemaking treatment (R. 3979-3980).

3. Petitioners contend that the Commission converted the proceeding below from a adjudicatory to a rule-making proceeding and improperly relied on extra-record evidence to support its policy decision, thereby depriving Petitioners of due process of law. Petitioners' contention is wholly without merit. Petitioners overlook the fact that the Commission's Opinion was solidly based on substantial record evidence and that the Commission merely looked to extra-record materials to bolster its findings. Stripped of all adornments, their argument amounts to nothing more than a claim that the Commission gave less weight to the evidence submitted by Petitioners than it gave to opposing evidence and would require this Court to re-examine independently the evidence of record contrary to Section 19(b) of the Act.

ARGUMENT

I

THE COMMISSION'S POLICY AS TO THE PRICING OF NEW GAS PRODUCED BY PIPELINES AND THEIR AFFILIATES IS REASONABLE, PROPER AND FAIR TO ALL PRODUCERS AND CONSUMERS

Since the commencement of regulation under the Act, the Commission has generally used the individual company cost-of-service

approach in regulating an interstate pipeline's gas production. But, the Commission did not regulate the price of gas sold in interstate commerce by independent producers until the Supreme Court's 1954 decision in Phillips Petroleum Company v. Wisconsin, 347 U.S. 672 (1954). After Phillips, it soon became apparent that it was not practical to attempt to regulate independent producers on an individual company cost-of-service basis. And, in Phillips Petroleum Company, 24 FPC 537 (1960), the Commission abandoned a fruitless six-year struggle to fix independent producer rates on the individual company cost-of-service method and began developing the "area rate" method for regulating prices for gas sold in interstate commerce by independent producers.[5/] In 1968, the Supreme Court's Permian decision[6/] established beyond dispute the legality and appropriateness of the area-pricing method of regulating independent producer sales.

5/ Under the "area rate" method, uniform rates are fixed for the sale of all gas of like quality and vintage produced from a given geographical area. To date, the Commission has established "just and reasonable" area rates for the Permian Basin and Southern Louisiana Areas. The "just and reasonable" area rates fixed by the Commission for new gas produced from those areas are based on the average nation-wide cost of finding and producing gas experienced by all producers -- including pipeline and affiliated producers. Proceedings to fix "just and reasonable" rates for four additional pricing areas are now pending, at various stages, before the Commission.

6/ In Re Permian Basin Area Rate Cases, 390 U.S. 747 (1968)

In Opinion No. 568 (the Order being reviewed here), the Commission proclaimed its intention henceforth to regulate pipeline producers (and their affiliates) ". . . on a parity with independent producers" (R. 11290). The question here is whether the Commission can use area-pricing techniques to regulate the price of new gas produced by pipelines (or their affiliates). Petitioners attack the Commission's Order principally on the grounds that:

1. Precedent compels the Commission to continue to regulate gas produced by pipeline companies on a cost-of-service basis;

2. Application of the area-rate method to pipeline producers would violate the "actual taxes paid" doctrine and result in excessive returns; and

3. The Commission converted the proceeding below from a adjudicatory to a rule-making proceeding, thereby depriving Petitioners of due process of law.

All of Petitioners' claims are wholly lacking in merit.

A. The Commission Is Legally Free To Apply Area Rates To Gas Produced By Pipelines (Or Their Affiliates) From Leases Acquired In The Future

Petitioners claim that existing legal standards prohibit the Commission from regulating gas produced by pipelines on an area-rate approach. None of the cases relied upon by Petitioners support their theory. To the contrary, existing precedent clearly indicates that the Commission is legally free to adopt a pricing system other than the conventional cost-of-service method and

apply "just and reasonable" area rates to new gas produced by pipelines (or their affiliates).

The Supreme Court has long held that neither the Constitution nor the Act tie the Commission to any particular rate-making formula, Federal Power Commission v. Natural Gas Pipeline Company of America, 315 U.S. 575 (1942); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

In Colorado Interstate Gas Company v. Federal Power Commission, 324 U.S. 581 (1945), one of the cases chiefly relied on by Petitioners, the Supreme Court took care to point out that (324 U.S. at 601):

> "We do not say that the Commission lacks the authority to depart from the rate base method. We only hold that the Commission is not precluded from using it."

And, in Wisconsin v. Federal Power Commission, 373 U.S. 294 (1963) at 309, the Court noted that it had:

> ". . . never held that the individual company cost-of-service method is a sine qua non of natural gas rate regulation."

The cases cited by Petitioners hold only that the Commission may regulate pipeline production on a cost-of-service basis and not that it is required to do so. As the Supreme Court observed in the Hope case, supra, at 602:

> ". . . it is the result reached not the method employed which is controlling. . . . If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. . . . and he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences."

Petitioners' theory rests principally on City of Detroit v. Federal Power Commission, 97 App. D. C. 238, 230 F2d 810 (D.C. Cir. 1955); *cert. denied* 362 U.S. 829 (1956). In its Opinion in that case, this Court did not hold that the Commission's attempt to permit a pipeline to claim the "fair field price" for its own production was unlawful under the Act because it departed from the traditional rate-base method. Indeed, it specifically rejected the contention that the traditional cost-of-service was the only method that could lead to a "just and reasonable" rate (230 F2d at 814-815).

In City of Detroit, this Court reversed the Commission's attempt to fix rates for pipeline-produced gas on the basis of the average, unregulated price paid for gas in the field. These unregulated contract prices bore no relationship to the cost. In

these circumstances, the Court found that the Commission's use of "fair field prices" failed to provide an objective standard to measure the "justness and reasonableness" of the result. Accordingly, this Court observed that the Commission must use cost as an "anchor" or "point of departure" if it desired to adopt a pricing system other than the conventional cost-of-service method.

Petitioners' attempts to equate "area rates" with the "fair field price" involved in City of Detroit, supra, overlook the fact that the "just and reasonable" rates established by the Commission in its Permian 7/ and Southern Louisiana 8/ decisions are based on the nation-wide average cost of all producers, including pipelines and their affiliates. Thus, the area-rate method supplies the "cost anchor" missing in the City of Detroit case.

B. The Commission's Policy Of Applying Area Rates To New Gas Produced By Pipelines Is Rationally Based, Supported By Substantial Evidence And Cannot Be Said To Be Unjust Or Unreasonable In Its Consequences.

The Commission's policy decision to treat all producers equally in all respects was designed simultaneously to encourage pipelines to increase their exploration and production activities,

7/ Area Rate Proceeding (Permian Basin Area), Docket Nos. AR61-1, et al., 34 FPC 159 (1965)

8/ Area Rate Proceeding (Southern Louisiana Area), Docket Nos. AR61-2, et al., 40 FPC 530 (1968), as modified on rehearing, 41 FPC 301 (1969).

and to insure the consumer that he will be charged no more than the "just and reasonable" area rate which the pipeline would be required to pay if it elected to purchase all of its supplies from independent producers. The shift to area pricing was prompted, at least in part, by the Commission's finding that the cost-of-service method led to a continuing reduction in the relative amount of pipeline production (R. 11283-11284). This finding is amply supported by the record. Contrary to Petitioners' claims, pipeline production has not prospered under cost-of-service ratemaking. As the Commission noted (R. 11284):

> ". . . the owned reserves of pipeline producers have declined 29.9 percent between 1958 and 1966, and, as a percentage of total reserves, have declined from 25 percent in 1958 to 13 percent in 1966."

In the opinion of the Pipeline Production Group's Witness Peck, the decline in pipeline production activities could be explained by the fact that the Commission applied different ratemaking methods to pipeline and independent producers (R.687-688). This difference in regulatory treatment created a competitive imbalance which has now been redressed by Opinion No. 568. It must be borne in mind that pipelines are required to compete with independent producers for the acquisition of leases and that pipelines and independents must deal with royalty owners on the same basis. In the final analysis, the price that a pipeline can afford to pay for a lease or a royalty agreement is determined by

the price the pipeline can expect to recover for the gas it finds and produces. Absent parity of ratemaking treatment, pipeline producers will be at a disadvantage when attempting to acquire new leases or obtain agreements with royalty owners.

The further irrationality of continuing to price pipeline production for gas produced by pipelines in the major Southwest producing areas on an individual company cost-of-service basis, once maximum rates are established for producers on an area basis, is clearly described in the Commission's Opinion (R. 11283):

> ". . . if a pipeline can purchase gas from independent producers in a given field at an area price fixed by the Commission, a most serious question is presented as to whether it would be in the public interest (and not unduly discriminatory) to permit a pipeline to charge its customers a substantially higher price for gas it produced itself from the same field merely because its overall costs of production for a particular test period turned out to be higher than the area rate. Conversely, if, as many of pipeline participants in this proceeding urge is the case, pipelines can successfully conduct production operations at the area rate fixed for independent producers, there is no reason why their consumers should be deprived of the benefit of such enhanced participation in the production area by industry elements specially concerned with the maintenance of an adequate gas supply, merely because some of the pipelines -- or even a majority of them -- can conduct such operations at a more profitable rate of return than we might allow the pipeline as a whole to earn on an individual cost-of-service basis." (Footnote omitted)

Although it is clear from Opinion No. 568 that the Commission did not ground its policy decision on a claimed supply shortage, it did note that it was arriving at its conclusion (R. 11284):

". . . at a time when there are indications of a shortage of gas and a threat of a greater shortage in the future. For instance, for the first time the American Gas Association reported that in 1968 net gas production exceeded the reserves added resulting in a decline in total proved reserves from 292.9 trillion cubic feet to 287.3 trillion cubic feet by the end of 1968. */

"While the 1968 figures are not in the record, the present trend is reflected by the record. Preeminent are the reserve-production ratios showing the ratio of reserves to production during the year. This ratio, for the United States, with some slight ups and downs, has trended generally downward from 22.1 in 1955 to 14.8 in 1968."

*/ AGA Committee on Annual Gas Reserves; Report issued April 7, 1969.

The Commission's conclusions with respect to the developing gas shortage were further buttressed by the FPC Staff Report on National Gas Supply and Demand, issued on October 1, 1969 (only six days before the issuance of Opinion No. 568), which concludes that only a few years remain before demand will outrun supply. The Fifth Circuit was recently prompted to state in Southern Louisiana Area Rate Cases (5th Circuit, Nos. 24792, et al., decided March 19, 1970), that the aforementioned Staff Report (Slip Opinion, pp. 54-55):

". . . is, at least from appearances, a careful, considered document. The record in this case does disclose instances in which Staff has been egregiously in error, (Footnote omitted) but we think there is something to its supply and demand report. The report is based upon quantitative projections of demand and several indicia of supply -- precisely the kind of 'assessment of consequences' that we find lacking in the Commission's decision here. Demands for Southern Louisiana's gas, according to the Staff

report, will be double its 1969 level in 1975. The FP ratio will remain below 1.0. The RP ratio will decline below 11 by 1973 even under the best of circumstances, and there is nothing that can be done at this time to maintain the ratio at its present level. The report further argues, and argues persuasively, that the inevitable decline in the RP ratio will probably cause regional supply deficiencies to come into existence as early as 1973. (Footnote omitted) And, aside from probable short-term deficiencies that cannot be prevented, Staff concludes that '/a/ major new government-industry program is needed immediately to insure the continued growth of natural gas service during the next decade.'" (Footnote omitted)

Finally, although it is not a matter of record in this case, it is significant to note that the Consolidated Natural Gas System Companies officially advised the Commission, prior to the issuance of the Order under review here, that they were then unable to contract for long-term supplies to meet the projected increases in customers' demands for the 1970-71 heating season.[9/] Ordinarily, Joint Intervenors contract for the additional flowing supplies needed to meet increased requirements several years in advance. Fortunately, the System has been able to purchase gas on a spot basis this summer. Nonetheless, the Consolidated Companies are still unable to contract for additional long-term supplies to meet the demands anticipated beyond the 1970-71 heating season.[10/] For this reason, the System has recently adopted

9/ See "Motion of Consolidated Natural Gas System Companies for Limited Reopening of the Southern Louisiana Area Rate Proceeding and for Other Action by the Commission" filed on January 31, 1969, in Docket Nos. AR61-2, et al.

10/ See Consolidated Natural Gas Company, Preliminary Prospectus, dated June 5, 1970, and filed with the Securities and Exchange Commission.

the policy of attempting to limit its sales to industrial customers to present levels and of slowing the growth of commercial sales, particularly those of large volumes.[11/]

Similarily, the National Fuel System has not been able to secure, as yet, the long-term supplies necessary to meet the demands anticipated for the 1971-72 heating season.

Petitioners' contention that the Commission must ignore the mounting evidence of an imminent gas shortage of serious proportions in formulating its policy with respect to future pipeline production is ill-founded. The Commission has, in the past, been affirmed when it relied on its general knowledge in formulating policies, cf. Alabama-Tennessee Natural Gas Company v. Federal Power Commission, 359 F2d 318 (CA 5, 1966); cert. denied, 385 U.S. 845 (1966).

II

THE COMMISSION'S TREATMENT OF RATE OF RETURN AND FEDERAL INCOME TAXES IS PROPER

As part of Petitioners' effort to overturn the Commission's Order here being reviewed, they contend that the application of area rates to gas produced by pipelines (or their affiliates) will violate the actual taxes paid doctrine and will result in excess rates of return for pipeline producers.

11/ See, Consolidated Natural Gas Company, Preliminary Prospectus, dated June 5, 1970, and filed with the Securities and Exchange Commission.

A. Federal Income Taxes

The rates fixed by the Commission in the Permian and Southern Louisiana decisions, supra, do not include an allowance for Federal income taxes. The record in both cases failed to establish whether, on an industry-wide basis, producers of natural gas incurred, on the average, either a tax liability or derived a net tax benefit. In the proceeding below, all parties (including Petitioners) stipulated that, in the aggregate, "an actual positive or negative tax liability cannot be determined from the data available in this record" (R. 5420). Nonetheless, Petitioners, relying on El Paso Natural Gas Company v. Federal Power Commission, 281 F2d 567 (CA5, 1960); cert. denied, 366 U.S. 912 (1961), claim that the application of area rates to pipeline production violates the "actual taxes paid" doctrine. Petitioners' contentions are wholly lacking merit. As the Commission observed, the holding in the El Paso case is inapposite where a pipeline's production activities are being regulated on an area-rate basis (R. 11289).

More fundamentally, however, Petitioners' claims are inconsistent with the basic concepts of area pricing, which is predicated on the overall cost experience of the entire production industry. As the Commission stated in Permian (34 FPC at 179):

> "Basic to this determination is the fact that objective cost standards for fixing just and reasonable rates for producer sales can best be developed by examining overall producer experience. An individual producer may find only dry holes or marginal wells or his search for gas may result in finding a huge new gas field. A price

> fixed by his individual cost experience could thus either be too high for consumers in relation to other available supplies or too low to be fair to the producer, considering his risks. However, on a group basis, costs and rates can be developed which will be fair to all concerned. A uniform ceiling price for the area will provide a fair relationship between the aggregate price the consumer pays and the aggregate costs that the producers incur."

Undoubtedly, some pipeline producers will incur a positive tax liability in some years, just as the production operations of some pipeline producers will generate "negative" income taxes in some years. The same is true for independent producers. In view of the fact that the record below does not establish, in the aggregate, a positive or negative tax liability for pipeline producers, there is no more reason to tailor the Federal income tax treatment to an individual pipeline company than there is to make an individual determination as to the actual taxes paid by independent producers.

Furthermore, under present Commission policy, independent producers are free to retain any "negative" tax benefits which may be generated by their production operations. This policy is an integral part of the incentive that is "built into" the area price for new gas. To deprive pipeline producers of the opportunity to utilize possible tax credits as a reduction in the other costs related to the production of gas would seriously disadvantage pipeline producers as compared with independents and would certainly reduce the incentive that pipelines would otherwise have to undertake further exploration and production activities.

The illogic of Petitioners' argument becomes apparent when one considers that pipelines may incur negative income tax liabilities because they are losing money on their production operations. It would be patently unreasonable, as Petitioners suggest, to reduce such an unfortunate pipeline company's resale rates even further. Conversely, pipelines having relatively profitable production operations and a "positive" income tax would have their resale rates increased (R. 3986-3988).

Customers of a pipeline whose production, sold at area rates, was highly profitable might with good reason wonder why this fact should require them to pay <u>higher</u> rates to the pipeline. And the pipeline with losses on its production might with equal reason wonder why this fact should cause it to <u>reduce</u> its rates.

B. Rate of Return

In both the <u>Permian</u> and <u>Southern Louisiana</u> cases, the Commission allowed a 12% rate of return which it applied to an industry-wide average rate base -- i.e., one half of the industry's gross investment. Petitioners assert that the application of area rates, designed to produce an average overall rate of return of 12% to the producing industry, will result in excessive rates of return when applied to pipeline-owned production. Petitioners conclude that (Petitioners' Brief, p. 46):

> ". . . any method of regulation which permits the pipeline producer an overall rate of return equal to that of the independent producer will put the pipeline in a position of super-parity, <u>vis a vis</u>, the independent producers."

Petitioners have focused on the cost of financing past pipeline ventures and erroneously assumed, therefore, that pipeline producers will be able to finance future production operations less expensively than independent producers by virtue of the fact that pipeline companies have historically been able to take advantage of higher debt/equity ratios. It is stating the obvious to note that pipelines cannot expect to finance future production operations as inexpensively as they have financed past pipeline operations. The record contains no evidence to support Petitioners' contention that pipelines will be able to finance future production operations more cheaply than the independents. But, it does contain evidence that the opposite may, in fact, be expected (R. 4063-4064 and 6126).

Moreover, the data in the record, relied upon in part by Petitioners, are already seven years old and reflect an industry average cost of imbedded debt of 4.75% (R. 503). Pipelines will not likely be able, in the foreseeable future, to sell debt securities at a cost anywhere near 4.75%. In fact, the present cost of debt issued by pipelines generally exceeds 9% and sometimes ranges up to 10½%.

Assuming, arguendo, that pipelines have in the past been able to raise capital on more favorable terms than independent producers, the Commission quite properly refused to view that special facet of a pipeline's production operations in isolation (R. 11286). It

must be remembered that rate of return is only one of the many components used by the Commission in determiing the cost of new gas which forms the basis for the area ceiling rate. In several of the other components, pipeline producers have tended to experience cost above the industry averages (R. 3980).

Most importantly, however, Petitioners' argument is fundamentally at war with the basic precepts of area pricing. It should be noted that area rates do not guarantee any producer that he will earn a particular rate of return. It merely gives the producer an opportunity to compete against a national benchmark, based on average industry-wide cost experience. If the individual producer is fortunate or unusually skillful, he will earn a high rate of return. If however, the producer's costs are above average, the return will be reduced correspondingly -- even to the point where the producer will, in fact, earn a "zero" or even negative return. But, this is exactly what the area-rate method contemplates. As the Commission observed in Permian (34 FPC at 179):

> "A uniform area pricing system is adapted to the economics of the natural gas industry. The producer who finds large reserves will achieve greater profits than the producer whose exploration efforts result in dry holes or marginal wells. Likewise, the producer whose enterprise is conducted with efficiency and economy will make more money than the producer who runs his business poorly. . . . True, individual returns will vary greatly, but this is as it should be, provided that profits in the aggregate are at a reasonable level."

III

THE PROCEDURES ADOPTED BY THE COMMISSION WERE NOT SO UNFAIR AND PREJUDICIAL AS TO HAVE DEPRIVED PETITIONERS OF DUE PROCESS OF LAW

Petitioners further contend that the Commission converted the proceeding below from an adjudicatory to a rulemaking proceeding and improperly relied on extra-record materials to support its Opinion, thereby depriving Petitioners of due process of law (Petitioners' Brief, pp. 57-69). Petitioners' claims ignore the fact that Opinion No. 568 is solidly founded on substantial record evidence and the Commission merely looked to "extra-record" materials to confirm its policy decision. Their claims amount to nothing more than a mere expression of dissatisfaction due to the fact that the Commission gave less weight to the evidence submitted by Petitioners than it gave to the opposing evidence. In effect, Petitioners are seeking a *de novo* review of the evidence contrary to Section 19(b) of the Act which requires affirmance of the Commission's Order if the Commission's findings are ". . . supported by substantial evidence."

Moreover, the changing picture in the gas supply situation is common knowledge in the industry and has been amply shown by facts that are daily coming to the attention of the Commission. In fact, the Commission Staff, prior to the issuance of Opinion No. 568, released its "Report on National Gas Supply and Demand" which concludes that demand will soon overtake supply. Joint Intervenors think it unreasonable to require the Commission to ignore the

report of its own Staff and shut its eyes to the plain facts of life as they exist in the industry when formulating policy with respect to future pipeline-owned production. Certainly, the procedures adopted below cannot be said to be so unfair and prejudicial to Petitioners as to have denied them a fair hearing, cf. Alabama-Tennessee Natural Gas Co. v. Federal Power Commission, 359 F2d 318 (CA5, 1966); cert. denied 385 U.S. 845 (1966). And, in any event, Petitioners have already been heard on the merits of their claims.

CONCLUSION

WHEREFORE, Joint Petitioners respectfully request that the Court affirm the Commission's Opinion No. 568 and accompanying Order.

L. R. Reif
10 Lafayette Square
Buffalo, New York 14203

Richard M. Di Valerio
308 Seneca Street
Oil City, Pennsylvania 16301

ATTORNEYS FOR IROQUOIS GAS CORPORATION, PENNSYLVANIA GAS COMPANY, UNITED NATURAL GAS COMPANY, Subsidiaries of NATIONAL FUEL GAS COMPANY

June 15, 1970

David E. Weatherwax
445 West Main Street
Clarksburg, West Virginia
26301

Henry P. Sullivan
4 Gateway Center
Pittsburgh, Pennsylvania
15222

Norman A. Flaningam
Charles R. Brown
744 Pennsylvania Building
Washington, D. C. 20004

ATTORNEYS FOR CONSOLIDATED GAS SUPPLY CORPORATION

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

City of Chicago, Illinois, City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee and The American Public Gas Association,	)	
Petitioners,	)	No. 23740
v.	)	
Federal Power Commission,	)	
Respondent.	)	

REPLY BRIEF FOR PETITIONERS

Richard L. Curry
Corporation Counsel
Mathias M. Mattern
Assistant Corporation Counsel
for Public Utilities
Bernard Rane
121 North LaSalle Street
Chicago, Illinois 60602

Max P. Zall
City Attorney
City and County of Denver
City and County Building
Denver, Colorado 80202

Charles F. Wheatley, Jr.
William T. Miller
Grace Powers Monaco
2600 Virginia Avenue, N. W.
Washington, D. C. 20037

Attorneys for Petitioners

Of Counsel:
George E. Morrow
Union Planters National
Bank Building
Memphis, Tenn. 38103

Reuben Goldberg
1250 Conn. Ave., N. W.
Washington, D. C. 20036

July 16, 1970

TABLE OF CONTENTS

TABLE OF CITATIONS

STATUTES

UNITED STATES COURT OF APPEALS

FOR THE DISTRICT OF COLUMBIA CIRCUIT

City of Chicago, Illinois, City and County of Denver, Colorado, the Memphis Light, Gas and Water Division, Memphis, Tennessee and The American Public Gas Association,	)	
Petitioners,	)	No. 23740
v.	)	
Federal Power Commission,	)	
Respondent.	)	

REPLY BRIEF FOR PETITIONERS

INTRODUCTION

The briefs of respondent Commission and the pipeline intervenors inaccurately characterize petitioners' arguments. It is not a simplistic historical argument, as the Commission brief asserts (Br. p. 9), "that since pipeline production has been regulated in the past by the individual company cost-of-service method with repeated court approval, no change should be made." Nor is the main thrust of our argument, as PPG intervenors mistakenly contend (Br. p. 2), "that the Commission is required to utilize the 'individual company cost of service' ratemaking method for future pipeline and affiliate production."[1/] The respondent and intervenors erroneously contend

1/ Petitioners do contend, however, that there is a serious question whether the Commission may depart from cost-of-service ratemaking for pipeline producers which must be preliminarily answered by this Court before the issue is reached of the validity of the abandonment of cost-of-service ratemaking under the circumstances of this case. (Initial Br. pp. 39-42).

that this case has in effect been decided by the Permian decision and unfairly characterize petitioners' position as an attack upon Permian. In point of fact, the petitioners support the concept of area rates for independent producers, as established in Permian, and are currently striving in Docket No. AR69-1 to maintain the cost-based approach to area ratemaking for independent producers, in the face of vigorous efforts by the latter, supported by the now-interested pipelines, to raise area rate ceilings on the basis of non-cost data. In short, the petitioners' position is not as it has been characterized by the respondent and intervenors.

The thrust of our initial brief is that the Commission has not sustained the heavy burden of proof placed on it by the Natural Gas Act as articulated by this Court in City of Detroit v. FPC 2/ that where the Commission seeks to abandon the established cost-of-service method for pricing pipeline produced gas in order to achieve a stated purpose, it must show through adequate findings based on substantial record evidence that the increase in rates is needed but is no more than is needed for the purposes advanced for the increase. As petitioners show below, the few relevant arguments of respondent and intervenors 3/ addressed to this jugular issue are contradicted by both the record evidence and the controlling law.

2/ 97 U.S. App. D.C. 260, 230 F.2d 810 (D.C. Cir. 1955), cert. denied, 352 U.S. 829 (1956).

3/ Except where the intervening parties offer something not found in the respondent's brief, this reply brief will focus primarily upon points argued in the Commission's brief.

ARGUMENT

I. THE APPLICATION OF UNMODIFIED AREA RATES DEVELOPED FOR INDEPENDENT PRODUCERS TO THE PRODUCTION FUNCTIONS OF PIPELINES VIOLATES THE PRINCIPLE ANNOUNCED BY THIS COURT IN THE CITY OF DETROIT CASE REQURING THAT COST OF SERVICE OF PIPELINE PRODUCERS BE USED AS A POINT OF DEPARTURE FOR ANY DIFFERENT APPROACH TO JUST AND REASONABLE RATES.

In City of Detroit this Court clearly specified that the current cost-of-service method of regulation must be used as a point of departure in comparing the presumed impact of a proposed alternative regulatory method on pipeline and consumer, thereby determining whether the alternative fulfills the criteria indicative of a just and reasonable rate:[4/]

> Unless it is continued to be used at least as a point of departure, the whole experience under the Act is discarded and no anchor, as it were, is available by which to hold the terms "just and reasonable" to some recognizable meaning.

In terms of this proceeding, then, area rates (the alternative method) must be measured against cost of service (the current regulatory method for pipeline producers) and the actual and projected results of the employment of these diverse methods compared to show that a need for a change from the current regulatory system exists and that the alternative system (area rates) will meet that need better than the current regulatory method and at the same time provide just and reasonable rates for the consuming public.[5/]

4/ 230 F.2d at 818.

5/ 230 F.2d at 813, 816-18.

The Examiner followed this procedure. [6] The Commission has not shown and indeed on the present record, could not show, that comparison. To avoid the responsibility of making that legally required comparison on this record, the Commission attempts to substitute the record in another proceeding, the Permian Basin Area Rate Case.[7] The Commission finds that since area rates were just and reasonable for independent producers, as determined in Permian, they must also be just and reasonable for pipeline producers. [8] The briefs of respondent and intervenors have attempted to divert the Court's attention from this failure to measure the effect of area rates on pipeline producers by arguing that the City of Detroit case was concerned with (unregulated) fair field prices whereas the instant

---

6/ R. 10071-10113.

7/ Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

8/ R. 10073-82.
The Commission attempts to convey the impression (R. 11282) that in extending area rates to pipelines they are merely following a course foreshadowed by the reasoning of Justice Jackson in Hope Natural Gas. In fact the approach adopted by the Commission and approved for independent producers in Phillips and Permian is the antithesis of the Jacksonian philiosophy. Both the Phillips and Permian approaches to regulation have a cost basis. Justice Jackson repudiates cost analysis and relevance and mistrusted accounting data and its relevance. It was Justice Jackson's position that "If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books." (FPC v. Hope Natural Gas Co., 320 U.S. 591, 650 (1944)). In fact, Commission Opinion No. 269, In the Matter of Panhandle Eastern Pipeline Co., (13 F.P.C. 53 (1954)) relied on Justice Jackson's analysis to support its fair field price valuation technique but was reversed by this Court in City of Detroit which reaffirmed the cost anchor and which established the principle that the performance of any new regulatory method must be measured against that cost anchor.

case involves (regulated) area rates. 9/ This reliance upon Permian as a "cost anchor", however, truly begs the question of justness and reasonableness of area rates, established in Permian for independent producers, for pipeline producers and in no way relieves the Commission of its regulatory duty to address this key issue. This critical omission by the Commission alone constitutes a reversible error.

The standard for judicial review of Commission action set forth in City of Detroit, namely that the Commission show that the record requires a change in regulatory method and that the type of change adopted by the Commission will satisfy the established need, -- was reiterated by the Supreme Court in Permian. In every particular, Opinion Nos. 568 and 568-A deviate from that standard set in Permian. The Supreme Court made it clear that adequate findings would be required: 10/

> Judicial review of the Commission's orders will therefore function accurately and efficaciously only if the Commission indicates fully and carefully the method by which, and the purposes for which, it has chosen to act, as well as its assessment of the consequences of its orders for the character and future development of the industry.

The Examiner concluded that the pipelines seeking the higher area rates failed to supply the specific evidence to satisfy the standard of the City of Detroit case. 11/ The Commission did not attempt to supply such evidence (in apparent recognition that the record evidence showed the reverse to be true) but rather seeks to

9 / Comm'n Br. pp 20-22; PPG Intervenor Br. 23-24.

10/ 390 U.S. at 792; also, FPC v. United Gas Pipe Line Co., 393 U. S. 71,73 (1968); Public Service Comm'n of N.Y. v. FPC, No. 23446 (D.C. Cir. June 29, 1970).

11/ R. 10125.

bridge the evidentiary gap by reliance upon the bare fact that area rates for independent producers are regulated, cost-based rates and thus may be applied to pipeline producers without adjustment for the significant differences between pipelines and independent producers. Not only is such a leap of faith in derogation of the principles set forth in the City of Detroit case which requires meaningful analysis of the proposed alternative area ratemaking concept with the current cost-of-service standard, but in addition it is undermined by the record evidence establishing the non-comparability on cost and other bases of independent and pipeline producers, as we show below. 12/

A. The Impact of the Rate of Return Issue Alone Demonstrates the Fallacy of Blindly Adopting Area Rates for Pipeline Producers.

Area rates developed in Permian and Southern Louisiana for independent producers include an overall rate of return component of 12%. This rate of return was designed specifically for the relatively high risk operations of independent producers who rely almost exclusively on high cost equity capital to finance their operations.

12/ The PPG intervenor resists such analysis under the heading "Indivisibilities of New Area Rate" (Br. p. 24 et seq.), arguing that petitioners err in examining the effect of the proposed area rates on the pipeline producers on the apparent (though obviously false) ground that pipeline producers are a "group of companies substantially less than the entire industry" (Br. p. 25) and thus defy analysis under Permian. But this is clearly not the message of Permian which, like the City of Detroit, places a heavy burden on the Commission to justify area rates for a separate class such as the pipeline producers.

This 12% overall rate of return was calculated in Permian to yield the independent producers from 10 to 12% return on equity and in Southern Louisiana approximately 13.3%. 13/ In sharp contrast to the above, as we point out in our initial brief to the Court (Br. pp. 45-50) and as the Commission Staff showed the Commission, 14/ application of this 12% rate of return to the low risk pipeline producers whose capital structure shows a high debt-equity ratio, 15/ produces an exorbitant return on equity of up to 40%. 16/ Incontrovertibly, application of area rates set for independent producers to pipeline producers results in windfall profits to stockholders of the pipeline producers at the direct expense of the gas consumer, as the Examiner so found. 17/

13/ 34 F.P.C. at 401; Austral Oil Co. v. FPC, supra, Slip. Op. p. 39 n.72.
14/ R.10996-97; see R. 494-500.
15/ PPG points out that capitalization ratios have changed slightly over the years (Br. p. 28 n.23) but declines to make the computation as to the effect of a 12% rate of return on pipeline producers as a class, obviously realizing that the result is virtually the same as shown by petitioners in the initial brief. PPC's further point that pipeline producers have varying capital structures (Br. p. 28 n. 23) is meaningless in measuring the effect of a 12% rate of return on pipeline producers as a class as compared with independent producers as a class.
16/ It is noteworthy that the highest overall rate of return allowed a pipeline to date is 7 1/2%, yielding a 10.35% return on equity. Algonquin Gas Transmission Co., Opinion No. 571 (Jan. 19, 1970). Significantly, the Commission has consistently refused to permit pipeline producers to earn a higher return on production operations than transmission operations. E.g., Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 601-02 (1945); Panhandle Eastern Pipe Line Co. v. FPC, 324 U.S. 635, 648 (1945); Southern Natural Gas Co., 29 F.P.C. 323, 335-38 (1963).
17/ R. 10131.

The Commission Counsel refers to the above evidence of record as "speculations" (Br. p. 24), and then gives as support for its position the Commission's refusal "to assume that in the future pipelines would, under the area rate approach, be in a position to utilize their debt resources for the riskier production activities to the same extent as for transmission facilities" (Br. p. 24). This unsupported Commission assumption that pipeline producers will in the future incur the same financing costs as independent producers flies in the face of reality. The Commission conveniently overlooks the fact that pipeline producers are first and foremost low-risk interstate transmission companies and raise capital from the public (and are rated by the bond-rating agencies) as such. In addition, as anyone familiar with pipeline rate cases knows, the pipelines do not trace their funds and thus it is impossible to determine whether moneys raised through a given debt offering are utilized on a pipeline project or a production project. Moreover, as the Commission Staff convincingly shows through its witness Shaffner, 18/ investors are attracted to basically low-risk companies like pipelines which offer the added potential of increased earnings by way of related operations involving a somewhat higher degree of risk. Clearly, pipeline producers as a class will continue as in the past to experience lesser capital costs than do independent producers, thereby exphasizing the irrationability of the adoption of a 12% rate of return for pipeline producers. 19/

18/ R. 493-99 (Staff witness Shaffner).

19/ The attempt by PPG to distinguish the pipeline rate of return from the area-rate rate of return on the ground that they are applied to different type rate bases (Br. p. 26) is meaningless insofar as the effect of a 12% rate of return on pipeline producers vis-a-vis independent producers.

Commission counsel argues that because of rising interest costs on debt capital, the 12% overall rate of return will not produce the exorbitant profits for pipeline producers that it otherwise would (Br. p.25). There are several flaws in this argument. In the first place, the 12% overall rate of return for independent producers was set at a given point in time in light of the cost of debt and equity capital at that time; in addition the 12% overall rate of return for independent producers was set with an eye on the 6-6 1/2% rate of return of the pipeline companies at that time. It is to be expected that as these circumstances change, the overall rate of return for independent producers will reflect these changes. Also in light of the Commission's allowance of a 12% rate of return for independent producers on the basis of the 6-6 1/2% overall rate of return of the lower risk pipelines, allowance of a 12% overall rate of return for pipeline producers would logically prompt the independent producers to request a proportionate increase in their allowed rate of return, which under the rationale of Opinion No. 568 under review here, would warrant the pipeline producer seeking a comparable return, ad infinitum. In brief, the attempt by the Commission to view the 12% rate of return outside of the context in which it was set for independent producers in an effort to dilute its demonstrated effect upon the return on equity of pipeline producers is patently fallacious.

It is especially significant that the Commission (apparently recognizing the unsupportable nature of its rate of return findings) states in Opinion No. 568 that its "principal objection" to the position that pipeline producer costs will be cheaper is the "basic assumption" that "the differential should accrue to the pipeline's ratepayers rather than to the pipeline." 20/ Thus, the Commission concedes that pipeline producers as a class will show greater profits than independent

20/ R. 11286.

producers as a class (for all the reasons set forth in the preceding paragraphs of this section of the brief) but it denies that these excess profits should accrue to the pipeline's ratepayers on the ground that "[t]his is virtually guaranteed to discourage pipelines from entering the production area to any large degree." 21/ One can only speculate with the Commission why the pipelines will be discouraged from entering the production area to any large degree if they are denied profits as a class in excess of those accruing to the higher cost independent producers. 22/ The Commission's conclusion that this differential in capital costs (and thus profits) between the pipeline producers and independent producers will provide a "greater incentive" to the former to explore for and develop gas reserves is exactly the open-ended type of finding that this Court found unacceptable in the City of Detroit case when it required that the Commission show that the increase in rates is needed and is no more than is needed for the desired purpose. Noticeably absent from the Commission's brief was any explanation for the added burden placed on the customers of pipeline producers by the adoption of area rates set for independent producers, other than to state that the Commission was on "sound ground" in allowing pipeline producers excess profits in that "failure to permit the pipeline to retain such differential would greatly diminish the incentive built into area pricing. . ." (Br. p. 26). The Commission in effect admits that it has put the pipeline producers in a position of super-parity vis-a-vis the independent producers, again showing the inadequacy of Permian as a "cost anchor" for pipeline producer rates.

21/ R. 11286-87.

22/ This result is particularly anomalous in light of the facts, as we show below, that the pipeline producers under cost-of-service ratemaking have outperformed independent producers under area ratemaking.

B. <u>The Area Rate Concept Developed in Permian Does Not Sanction Violation of the "Actual Taxes Paid" Principle.</u>

Petitioners have shown that the "actual taxes paid" principle established by the Commission and enforced by the courts requires that pipeline customers pay only the actual expenses incurred by the pipeline company (Initial Br. pp. 51-56). The courts have repeatedly refused to permit the pipelines to charge a hypothetical tax expense to their customers in order to provide an incentive for any purpose. <u>E.g.</u>, <u>El Paso Natural Gas Co.</u> v. <u>FPC,</u> 281 F.2d 567 (5th Cir. 1960), <u>cert. denied,</u> 366 U.S. 912 (1961). The application of unmodified area rates to the pipeline producers as here proposed will, however, violate this principle every time a pipeline producer has a negative tax (i.e. tax credits) because these credits will reduce the actual taxes paid by the pipeline but the pipeline customer will continue to pay rates based upon a higher hypothetical tax expense never in fact incurred by the pipeline. 23/ The Commission's Staff in its brief to the Commission, urging the adoption of the area rate concept, demonstrated that area rates could only be applied legally to the pipeline producers if modification were made to account for the actual taxes paid principle. 24/

23/ PPG would attempt to avoid this point by arguing that since there is no basis for assuming in the aggregate that there will be spillovers, it is somehow unimportant that individual pipeline companies may violate the actual taxes paid principle (Br. p. 29). Again PPG errs in its attempt to lump everything together to avoid analysis. The point is that pipeline rates are regulated on a company-by-company basis and therefore spillovers become significant in determining the just and reasonable rate for any given individual pipeline, as the courts have repeatedly held. <u>E.g.</u> <u>El Paso</u>, <u>supra.</u>

24/ R. 11001-10.

The Commission, however, in its illusive pursuit of "parity" for pipeline producers and independent producers has here ignored one of the basic differences between the two classes of producers, that the production arm of a pipeline is but one segment of a regulated entity and thus cannot be viewed in isolation. Respondent and intervenors have offered nothing which overcomes this fundamental fact and would warrant this Court in turning its back on the actual taxes paid principle as we show below.

In the first place, this principle was not an issue in the Permian case in which any spillovers (if they should occur) would affect only unregulated businesses whose prices are determined by the market place and not under the auspices of a regulatory Commission. 25/ This is distinct from our own case in which the spillovers reduce the actual taxes paid of a regulated pipeline whose customers are obliged to compensate the company only for taxes actually incurred. The instant case is analogous to the situation in FPC v. United Gas Pipe Line Co., 386 U.S. 237 (1967) in which a pipeline company's tax allowance was reduced to its actual taxes paid to the extent that other affiliated unregulated companies which had filed a consolidated tax return had tax spillovers. A fortiori in our own case, the spillovers from a regulated adjunct of the pipeline company must be accounted for in the computation of the pipeline's tax allowance.

PPG attempts to use Permian and Southern Louisiana as an umbrella to cover the instant case by arguing that in those cases no Federal or state income tax allowance or component was included in computing new gas area rates, from which PPG mistakenly concludes that "[h]ence, there can be no 'fictitious or unreal tax expense' as in

---

25/ See 34 F.P.C. at 206-07, 388; 390 U.S. at 824 n. 115.

City of Lexington, Kentucky v. FPC, 295 F.2d 109 (4th Cir. 1961). . ." (Br. p. 29). The PPG logic is unsound since the fact that area rates contain no tax component (due to the fact that independent producers on balance pay no taxes) does not alter the fact that where a pipeline producer does have tax spillovers (regardless of whether or not a tax component is included in the area rate), it is obligated by law to pass these spillovers on to its customers who are required to reimburse the company only for its actual taxes paid. Thus, the attempt by the Commission to phrase the issue as though all that mattered is whether the "industry as a whole on the average" paid Federal taxes (R. 11290) does not in any sense relieve it of the burden in pricing interstate sales of gas by pipelines from insuring that the rates established under the Act reflect only the pipeline's actual taxes paid. FPC v. United Gas Pipe Line Co., supra. And furthermore there is no magic in the word "parity" which permits the Commission to avoid its ratemaking responsibilities under the Act to maintain "just and reasonable" pipeline rates, which by definition requires that only actual taxes paid be included therein.

In its brief the Commission first states that it is cognizant of its duty under the El Paso and City of Lexington cases to see that pipeline rates reflect only actual taxes paid (Br. p. 28) but then offers the following as the basis for escaping this duty (Br. p. 29):

> Indeed a predicate of the composite return used in the independent producer rates is the possibility that an individual producer may have such tax benefits available to it. If pipelines were disallowed such benefits while receiving the same rates, they would in fact be short changed and not be accorded the same incentives as producers.

The Commission mistakenly views tax credits as "incentives" which thereby become immune from the actual taxes paid principle. But tax

component of area rates like the other cost components (aside from rate of return) were not designed on an incentive basis but rather were intended to wash out. Thus, the notion that the pipeline producers are somehow "short changed" because they cannot charge their pipeline customers excess rates is ill conceived. The Commission's Procrustean attempt to achieve parity on this issue between two distinctly different classes of operators again vividly demonstrates the fundumental flaw in the Commission's underlying premise.

C. The Commission's Decision That Area Rates Established in Separate Proceedings for Independent Producers Should Be Adopted for Pipeline Producers Despite Record Evidence Demonstrating Non-Comparability Requires Reversal.

Examiner Lande recognized and the Commission did not dispute that the key to effective group pricing is cost comparability, -- comparability not in terms of a comparison of the average price attributed to gas produced by pipelines with the average price of gas produced by independent producers, but rather the extent to which the individual companies approach or deviate from the median price.[26/] The Commission erroneously intimates, in its attempt to discredit and disregard the evidence adduced, that the conclusions of Examiner Lande were based on historic rather than prospective cost estimates.[27/] However, the Examiner's conclusions that pipeline new gas costs do not possess sufficient comparability to support application of a group pricing method did not depend upon historic cost data but were related completely to an evaluation of the

---

26/ R. 10073-82

27/ R. 11284-86; Comm'n Br. p. 8.

only evidence of record (submitted by PPG witness Jones) concerning "future new gas cost for pipeline producers." 28/

After an extensive examination and evaluation in his opinion, Examiner Lande found that the PPG new gas cost data was inherently defective and that when tested by cross-examination and rebuttal analysis the data advanced to support comparability, based on projected future new-gas costs, rather than establishing comparability demonstrated the wide variation of pipelines from any norm or median gas cost. 29/ The Examiner also found that since the cost-comparability data relating to prospective gas costs was inaccurate, the conclusions drawn from that data which depended on the accuracy of that data, namely, that (a) any decline in exploratory activity was due to differences in rate treatment between independent producers and pipeline producers, and (b) that sources of investment funds were similar for both pipeline producers and independent producers, were also tainted. 30/ It is significant that the Commission concludes that the "relative" decline in E&D for pipelines is the result of the cost-of-service method without showing a causal relationship, without findings or basis in the record. As demonstrated below, such a presumed connection is fallacious and cannot be based on this or any record. Also, the Commission concludes contrary to the position of its Staff in the proceedings below that the pipelines are not in a superior position vis-vis independent producers in relation to investment funds. 31/ Again the Commission is deficient in that it does not indicate the findings or reasoning on which it bases this crucial conclusion.

28/ R. 10084.

29/ R. 10073-10082.

30/ R. 10078-79.

31/ R. 10108-09.

It is apparent that the Commission is acting in complete disregard of the pertinent record findings and without findings and reasons to adequately support its conclusion when it speculates that:

> We know of no reason, on the basis of a knowledge of the industry, why pipelines should not be able, regardless of their past methods and policies to produce gas at as low a cost as the independent producers. 32/

This exercise in speculation by the Commission as noted is patently deficient in that the Commission fails to make adequate findings to support its conclusion as required by the Administrative Procedure Act. 33/ These required reasons or bases for the Commission's conclusions, moreover, must be supplied by the Commission; they cannot be supplied by counsel for the respondent or intervenors:

> . . .the reviewing courts have a right to know the basis for the Commission's ruling. The after-the-fact theories of counsel for the various defendants cannot meet the shortcomings of the present record. . . 34/

It is imperative that this Court not be mislead by the gloss put on the proceedings below by the respondent and intervenors that Opinion Nos. 568 and 568-A under review herein are supported by the record. The briefs of the aforementioned parties are in large part not relevant to this proceeding because they abound in miscellaneous untested reasons why the Commission should be allowed to do what it did. But they avoid the particular issue of whether the Commission's action is justified on the record established in this case and whether the Commission has complied with APA requirements in specifying its findings, conclusions and the reasons and basis therefor.

32/ R. 11361.

33/ 5 U.S.C. § 557.

See, e.g., Florida v. United States, 282 U.S. 194, 213 (1931); Colorado-Wyoming Co. v. FPC, 324 U.S. 626, 634 (1945); United States v. Pierce Auto Lines, 327 U.S. 515 (1946).

34/ Central & Southern Motor Freight Tar. Ass'n v. United States, 273 F.Supp. 823, 833-34 (D. Del., 1967).

The absence of required findings is fatal to the validity of any administrative decision regardless of whether there may be record evidence to support proper findings. Saginaw Broadcasting Co. v. FCC, 68 App. D.C. 282, 96 F.2d 554, 563 (D.C. Cir. 1938).

Further, the Commission's rationale that since area rates were found acceptable for independent producers in Permian they are *ipso facto* acceptable for pipeline producers, contravenes the established legal standard that legislatures and administrative agencies may calculate rates for a regulated class *provided* they have before them evidence which is representative and ample in quantity to measure with appropriate precision the financial and other requirements of the pertinent parties. 35/ Examiner Lande found and the Commission did not dispute that the Staff cost data in the record of the Permian proceedings, upon which the Commission based its unit cost conclusions, did not even include representative data on pipeline production operating costs. 36/ The Commission indicated, however, (R. 11286) that the Permian area rate experience applies equally to pipeline producers because the computations therein were based "upon industry-wide statistics which included the current production experience of the pipelines." This reliance is misplaced. The "new gas cost" in Permian and Southern Louisiana was based on industry data which, though including some pipeline data, does not come close to satisfying the necessary legal standard requiring that the data be representative and typical as to the pertinent parties. 37/ Therefore the data of the individual pipeline must

---

35/ *See* Tagg Bros. & Moorhead v. United States, 280 U.S. 420 (1930); Acker v. United States, 298 U.S. 426 (1936); United States v. Corrick, 298 U.S. 435 (1936). *Compare* New England Divisions Case, 261 U.S. 184, 196-99 (1923); United States v. Abilene & S.R. Co., 265 U.S. 274, 290-291 (1924); New York v. United States, 331 U.S. 284 (1947); Chicago & N.W.R. Co. v. A.T. & S.F.R. Co., 387 U.S. 326, 340 (1967).

36/ R. 2162, 2227 (Staff Stipulation). The findings by the Supreme Court in Permian that "The information used by the Staff, and ultimately adopted by the Commission, was taken from questionnaires submitted by 42 Major producers, which together account for 75% of all the gas produced in the Basin, and 85% of all the gas-well gas " (390 U.S. at 802 (emphasis added)) supports the Staff's stipulation. In fact the Commission excluded small producers' costs from the flowing gas cost compilation in Permian because the sample was not random and was too small to be representative (34 F.P.C. 159, 214). Also the Pipeline Production Questionnaire data collected for ... this proceeding will not permit a cost determination for the pipeline respondents herein since operating costs were not included. R. 2252-53.

37/ See cases note 35 *supra*.

not only be included in the computation, it must be properly reflected therein. Individual pipeline costs to the extent included in the "industry" data were not broken out from this data and were not arrayed or studied to determine comparability. Moreover, the pipeline respondents relative weight in the industry is so small that any "inclusion" of pipeline data in industry data would not substantially affect an industry average and therefore that average could not meaningfully reflect the pipeline data.[38/]

The Commission made it clear in Permian that the major producers which accounted for most of the production in the Permian Basin operated on a national basis and experienced costs over a period of time similar to the industry average which the Commission determined from and based upon national data.[39/] The Supreme Court, in Permian, stated:

> The Commission derived the maximum rate for new gas-well gas from composite cost data intended to evidence the national costs in 1960 of finding and producing gas-well gas. It reasoned that these costs should be computed from national, and not area, data because first, the larger producers, conduct national programs of exploration, and, second, "much, if not most of the relevant information" was available only on a national basis. . . 40/

Examiner Lande affirmed this conclusion, and contrasting pipeline producers thereto found that the pipelines operate to support their utility function, confining their drilling activities which differ in emphasis from the independent producers, essentially to areas adjacent to their respective systems and not therefore operating on a national basis.[41/] The Commission's conclusion that area rates for independent producers, based on national costs, can be applied to pipeline producers is deficient according to APA standards in that the Commission does not dispute the

38/ See El Paso Natural Gas Company Brief Opposing Exceptions, R. 1168-70.

39/ 34 F.P.C. 159, 190-91. See Permian Area Rate Case, 390 U.S. at 800 and the Brief for the FPC to the Supreme Court of the United States, October Term 1967, The Permian Basin Area Rate Cases, Nos. 90, et al., at pp. 24-25.

40/ 390 U.S. at 800 (emphasis added.)

41/ R. 10076, 10078, 10081.

Examiner's distinction between independent producers and pipeline producers in national versus area development; does not find that pipeline producers also produce on a national basis; and does not provide any basis for rationally discounting the significance of the national versus area differentiation.

Examiner Lande found that the observations made in Permian concerning the fundamental differences between large and small independent producers apply also to illustrate some of the differences between the independents (large producers) and the pipelines (small producers), In Permian the Commission recognized that:

> The basic difference between the small and the large producer is that risks of the business are materially different for each. The small producers exploratory activity is not extensive enough to afford him the likelihood of achieving average results, whereas the large producer over the years can approach this result. 42/

The PPG chief witness in the instant proceedings, Mr. Elmer, verified the Commission's conclusion in Permian.[43/] If, byconcession of the group on whose evidence the Commission has obviously relied, there is in fact not sufficient comparability to support group pricing of small independent producers, it is difficult to see how the Commission could find any basis in the record to conclude that the group pricing system could operate effectively for pipelines, whose cost experiences diverges even further from the median than that of the small independent producer. It is evident that the only proposition established by Permian is that when area rates are applied to large independent producers operating on a national basis, these producers will experience costs over a period of time similar to the industry average. The defect in any attempt to apply a method based on large independent producer experience to small

42/ 34 F.P.C. at 159, 234, 360.

43/ R. 3108-09 (PPG Initial Brief to the Examiner).

pipeline producers based merely on the wishful, unsupported hopes of the Commission relating to the eventual equation of median cost experience is evident.

The Examiner used the illustration of the Commission in Permian contrasting large and small independent producers to emphasize the divergence between independents and pipelines; however, he did not imply that the small producer and the pipeline producer are in fact comparable. Rather, he urged that there are important differences between the pipelines and the small independents: (1) the deviation from average cost for pipelines is much greater than for independent producers; (2) variation is the rule rather than the exception for pipelines; and (3) pipelines are already being regulated under an effective method of regulation which gives recognition to individual cost peculiarities; by contrast, the alternative in the case of the small independent producers seemingly would have been either an exemption from regulation, which would allow a penetration of rate ceilings disruptive of uniform area ceilings, or individual cost-of-service hearings for the over 3,000 small producers involved in production of gas being sold in interstate commerce, which would mean that adequate regulation of independent producers would be impossible under the existing law. 44/

In a rather overt attempt to divert the Court's attention from the deficient record, especially as regards cost comparability, respondent and intervenors repeatedly refer throughout their briefs to the alleged inability of cost-of-service pricing to provide the necessary incentive to pipelines to produce gas, asserting that area rates are the panacea. 45/ But the evidence of record shows clearly that by any meaningful indicia, the pipeline producers under cost of service have outperformed the

44/ R. 10076, 10080-82.

45/ Comm'n Br. pp. 12-13, 17, 18, 19 ; FPG Br. pp. 18, 19, 24.

independent producers under area rates. 46/ For example, the reserves to production (R/P) ratio, which the Fifth Circuit recently found so meaningful in analyzing the poor performance of independent producers under area rates, 47/ has remained relatively stable and higher for the pipeline producers in contrast to the sharp decline experienced by the independent producers. 48/ The discussion by the Commission in Opinion No. 568 (R. 11283) regarding the "continuing reduction in the relative amount of pipeline production" badly misses the mark because this is readily accounted for, not by FPC ratemaking policy, by the post-World War II entry into the natural gas production arena of many independent producers whereas the number of pipeline producers (whose main function is transmission not production of gas) has remained relatively stable. Petitioners invite the Court's attention to the thorough explanation of these circumstances by MGG witness Melwood Van Scoyoc at R. 4221-28 . The significant point overlooked by the Commission is the steady growth of pipeline production in terms of investment and output. 49/ The intimation by respondent (Br. p. 14) that cost of service is an unworkable approach to pricing pipeline produced gas is amply refuted by the facts that the Commission has successfully applied cost of service for over thirty years and that this utilization of cost of service has been accompanied by continued growth. 50/

46/ R. 5809-19; 967-32; 4219, 4228-29.
47/ Austral Oil Co. v. FPC, *supra*, Slip Op. pp. 52-55.
48/ Staff Exh. No. 6, p. 3; R. 5740. See p. 32, *infra*.
49/ See note 46, *supra*.
50/ Commission's point as to "erratic" production costs (Br. p. 14) is misleading because for those companies whose costs do vary significantly, the cost-of-service method utilizes an average cost which removes any possibility of unfair treatment for the pipeline or the consumer.

As to the efficacy of area rates to stimulate production, the independent producers have been strongly contending that cost-based area rates are the cause of the alleged gas supply problem, citing their declining R/P and F/P ratios, and have urged that cost pricing for area rates should be abandoned or at the very least the area rate ceilings should be raised dramatically. 51/ The pipelines, economically motivated to higher area rates under the Commission decision below adopting area rates for pipeline producers, have abandoned their formerly neutral stance and now fervently support the demands of the independent producers for spiraling area rate ceilings. 52/ The volatile status of area rates is further dramatized by the Commission itself which has indicated its second-thoughts on the area rate approach, as aptly illustrated by the remarks of Commissioner Bagge, of the FPC: 53/

> A decade ago, after a period of similar introspection and reexamination of its goals, the Commission initiated an innovative proposal. It conceived it to be the solution to the monumental problem of producer price regulation. It rejected a pricing methodology based upon the costs of individual producers. It proposed instead that prices be derived from the financial requirements of the industry as

---

51/ See Austral Oil Co. v. FPC, supra, Slip Op. pp. 40-60.

52/ Austral Oil Co. v. FPC, supra, Slip Op. p. 2, n.2.
The Commission's argument (Br. p.20) that the pipelines have not in the past been an effective bargaining agent ignores the Supreme Court's observation in Permian that at least the market is structurally competitive (390 U.S. at 757) and it ignores the impact of having the pipelines join the ranks of the independent producers to push area rate ceilings ever upward. PPG's argument that we are precluded from arguing this point because it was not excepted to -- is factually inaccurate. MGG Exception No. 9, R. 11312.

53/ Address by Carl E. Bagge, Comm'r, FPC, before the Midwest Gas Ass'n, 65th Annual Convention, Feb. 24, 1970 at 16-17. See address by L. J. O'Connor, Comm'r, FPC, before the Petroleum Accounting Conf., May 16, 1969 at 17 wherein he states, "One of the major criticisms leveled against area ratemaking is that there is insufficient incentive for uncovering new gas supplies."

a whole. It characterized this process as area rates. This policy resulted from the realization that the traditional rate base method of utility regulation did not lend itself to the determination of the rates of independent producers.

Today, after a decade of industry-wide cost-based area rates, the regulatory process is equally as frustrated as it was in 1960. If we are candid, it must be acknowledged that we have failed the "practical test" which we established for ourselves in Permian. Individual company ratemaking having been determined to be unworkable and cost based area ratemaking having been demonstrated tobe workable, the necessity for squaring producer prices with the market should now be clear. In the short term this overriding fact must be reflected in the adoption of indices which at least recognize market realities. In the long run, however, the market will inevitably prevail and regulation will be totally ineffectual to influence price.

We are obliged, therefore, to establish the policies now which will permit the inevitable ascendancy of market forces to operate in such a way as to work for the public just as they do in most other areas of our economic life. This, in the final analysis, can only be achieved if the market can operated unfettered by regulation and if, prior to that time, government policies are evolved which will affirmatively enlarge the supply base by broadening the base supply and increasing the supply sources. This, I submit, is the new goal of this new decade, It must be achieved by a national commitment which insures that the potential which this industry offers to the quality of life will be fully realized in this decade and in the decades to come.

Thus, contrary to the gloss put on this case by the respondent and intervenors that area rates for pipeline producers means more gas at less cost, the experience of the independent producers teaches a different lesson. The only guarantee is that under area rates pipeline producers will reap excess profits. Fortunately for the consumer there is no need for the Commission to experiment with area

rates for pipeline producers because their performance under cost-of-service ratemaking has demonstrated their ability to continually expand their production operations. It would be the height of regulatory folly for the pipeline producers to be allowed to switch from cost of service to area rates at a time when the very independent producers for whom area rates were designed are urging (with some success, judging from the remarks of Commissioner Bagge) that area rates should be guided by market -not cost- forces, for this is the nirvana (fair field prices) previously sought by the pipelines but denied to them by this Court in the City of Detroit case.

II. THE ACKNOWLEDGED REASON FOR THE COMMISSION SUPPLANTING THE TRADITIONAL COST OF SERVICE APPROACH FOR PIPELINE PRODUCTION OPERATIONS WITH UNMODIFIED AREA RATES IS AN ALLEGED GAS SHORTAGE, THE FACT AND CAUSE OF WHICH HAVE NOT BEEN ESTABLISHED IN THIS PROCEEDING OR ELSEWHERE.

The catalyst for the Commission's departure from its traditional individual company cost-of-service approach to regulation of the production operations of pipeline companies is what the Commission refers to at the outset of its opinion as "an apparent gas shortage", stating as follows:[54]

> This is a turning point in the regulation of pipelines owning their own reserves, but it follows closely upon the development of area regulation for the independent producers and a changing picture in the gas supply situation as shown by the record and other facts coming to our attention. In the light of an apparent gas shortage we are concerned whether the pipelines will make an increased effort to explore for and develop new gas reserves. We are also concerned whether new gas supplies will be available to the consumers of gas served by the long pipelines. To attain these ends it may be incumbent upon us to modify traditional approaches to regulation with respect to pipeline production in order to provide a regulatory climate conducive to an aggressive pipeline exploration program.

This keystone of the Commission's order is founded on two premises: (1) a gas shortage "apparently" exists; and (2) its presumed cause is attributable in part to lagging exploration efforts by pipeline producers, presumably the result of inadequate price incentives under current regulatory practice. Neither premise is supported by the record. As to the first premise, the Commission buttresses its assertion of "indications of a shortage of gas and a threat of a greater shortage in the future" by relying on figures from an April 1, 1969 report of the American Gas Association Committee on Annual Gas Reserves, which

---

54/ R. 11281.

it acknowledges "are not in the record." 55/ However, it finds these figures supported by record evidence of a general downward trend of the ratio of reserves to production from 1955 to 1968. 56/

The industry orientation of this report and the dubious reliability and relevancy of its statistical information are discussed at pages 63-69 of our initial brief. Respondent's effort to play down the significance of the gas shortage assumption to the decision in this case 57/ is understandable in light of this Court's recent reversal of the Commission in Public Service Comm'n of N.Y. v. FPC, No. 23446 (D.C. Cir., June 29, 1970) on the grounds of inadequate findings as related to the issue of gas supply, but is belied by the emphasis placed on this factor in the Commission's opinion. The PPG intervenors take anouther tack, contending that the AGA material can be officially noticed by the Commission by reason of its expertise, since it is "knowledge which is now shared, not only by experts such as the Commission, but by all informed persons". 58/ The flaw of this assertion is demonstrated by the fact that the Commission is presently conducting two investigations (Docket Nos. AR69-1 and AR70-1) the subject of which is the very factual situation assumed in this proceeding, i.e. whether in fact a gas shortage exists and, if so, its causes and possible solutions.

AR69-1 was triggered by a petition filed with the Commission by the New York Public Service Commission which the Commission characterized as follows in its order instituting the AR69-1 proceeding: 59/

55/ R. 11284.

56/ R. 11284. In its Opinion 568-A, clarifying Opinion 568 and denying rehearing, the Commission acknowledge that the PPG figures it relied on were subject to criticism (R. 11359). These deficiencies had been noted by the Examiner throughout his decision. See, e.g., R. 10073-82.

57/ Comm'n Br. p. 32.

58/ PPG Br., pp. 33-34.

59/ Order Instituting Investigation and Proposed Rulemaking, Docket No. AR69-1, March 20, 1969, pp. 1-2.

On January 8, 1969, the New York Public Service Commission filed a request that the Commission institute an investigation into the adequacy of gas reserves held or controlled by the major producers and pipelines, and the claims of a shortage of natural gas. In explaining its reasons why it believes an investigation is necessary, the New York Commission referred to a December 16, 1968, letter sent by the American Gas Association to the Commission which it interprets as asserting that distributors and pipelines are being refused service by many producers on the ground that the prices found in our area decisions to be just and reasonable are inadequate. The New York Commission gave three reasons why such a refusal to serve, if it exists, is sufficiently serious to warrant formal investigation:

> First, such a shortage, if proven on an evidentiary record, would require a review to determine the reasons therefor and the appropriate regulatory response thereto.
>
> Second, to the extent that the actual or threatened withholding of gas was being used to coerce parties to FPC proceedings to modify their positions, it would be essential for the FPC to take corrective measures to protect the integrity of its processes.
>
> Third, any group effort to fix the price at which natural gas shall be sold in interstate commerce, and any group refusal to sell gas to particular customers, would constitute 'apparent violations of the Federal antitrust laws' which the Commission is obliged to call to the attention of the Attorney General under Section 20(a) of the Natural Gas Act.

As recently as June 17, 1970, in its order instituting the new Permian Basin proceedings (AR70-1), the Commission provided that Phase I of the proceeding would be confined to, among other issues, "evidence with respect to the adequacy of gas supply and adequacy of service to consumers, the demand for gas, the cause of a gas shortage, if any . . ."

Such inquiries, which involve full evidential hearings with the right of cross-examination, would obviously be unnecessary if the existence and causes of a national gas shortage were already established, as the PPG intervenors allege.

Moreover, the Fifth Circuit in its recent Southern Louisiana [60] decision (much cited by the respondent and intervenors as conclusively establishing the existence of a serious gas shortage) [61] while expressing concern over "the possibility of severe gas shortages," [62] makes it clear that some further definitive action by the Commission is necessary on this vital issue. The Court's concern with the gas shortage possibility is tempered with recognition of "the frequency with which this argument has been effectively categorized as a 'cry of wolf'. . ." [63] It criticizes "the Commission's failure to make thorough findings on the matter" [64] but concedes that "this Court cannot itself evaluate the supply situation or determine what action is needed", since it does "not know whether the information that has reached us is correct or not." [65]

It is not enough, as the respondent's and intervenors' briefs suggest, that there are bits and pieces of the record in this case that relate to the question of gas supply. The fundamental issue, considering the paramount consumer interest which is at the heart of the Natural Gas Act, is whether the Commission has carried out its obligation to develop an adequate record on the gas supply issue, which is fundamental to the Commission's decision.[66] Where the broad interest of the public is involved, as here, the Commission has an affirmative duty to develop a comprehensive record.

60/ Austral Oil Co. v. F.P.C. (No. 27492, Mar. 19, 1970).
61/ Comm'n Br., p. 32; PPG Br., pp. 35-36.
62/ Austral Oil Co. v. F.P.C., Slip Opinion p. 56 (emphasis added).
63/ Id. at 53. In a footnote to its "cry of wolf" reference, the Court recited some of the well-known history of this argument (Slip Op. p. 53 n. 97). A more recent effort along these lines was the unsuccessful attempt to preserve certain industry tax incentives, primarily depletion rates, against restriction by Congress in the Tax Reform Act of 1969.
64/ Id. at 56.
65/ Id. at 58.
66/ E. g., Public Service Comm'n of N.Y. v. FPC, No. 23446 (D.C. Cir., June 29, 1970).

The Second Circuit has stated it more strongly:[67/]

> If the Commission is properly to discharge its duty in this regard, the record on which it bases its determination must be complete. The petitioners and the public at large have a right to demand this completeness . . .
>
> * * *
>
> In this case, as in many others, the Commission has claimed to be the representative of the public interest. This roll does not permit it to act as an umpire blindly calling balls and strikes for adversaries appearing before it, the right of the public must receive active and affirmative protection at the hands of the Commission.

In the subject case, the public did not even get a chance to come to bat, since the gas shortage issue was never litigated.

It should be obvious that this critical evidentiary void cannot be filled by utilization of the American Gas Association statistics in the manner employed by the Commission, namely, to bootstrap an apparent record on the gas supply situation through the wholly improper use of the doctrine of official notice. To permit the Commission to do so would violate fundamental concepts of due process and make a mockery of the administrative process, whether the proceeding is considered adjudicatory or in the nature of rulemaking.

The leading case in support of this rule as it applies to official notice in a ratemaking proceeding and which bears a close resemblance to the Commission's action in this case is Ohio Bell Telephone Co. v. Public Util. Comm'n.[68/] That case involved an order reducing the rates of a telephone company which was arrived at by modifying the value, established by the record evidence, of the company's property as of a certain date, by the percentage of decline or rise indicated during subsequent years by price trends as reflected in statistics published in a trade journal,--the Engineering News Record. The State Commission

67/ Scenic Hudson Pres. Conf. v. F.P.C., 354 F.2d 608, 612, 620 (2d Cir. 1965), cert. denied, 384 U.S. 941 (1966). See also Udall v. F.P.C., 387 U.S. 428, 451 (1967).

68/ 201 U.S. 292 (1937).

took notice of the price trends subsequent to the closing of the record. The company moved for a rehearing stating that (1) the trend percentage accepted in the findings as marking a decline in values did not come from any official sources which the state Commission had the right to notice judicially; (2) that the statistics had not been introduced in evidence; and (3) that the company had not therefore been given an opportunity to explain or rebut them and thus had been denied a fair hearing in contravention of the requirements of the Fourteenth Amendment. 69/

In an opinion by Mr. Justice Cardozo, the Supreme Court unanimously held that indeed the company had been denied the fundamentals of a fair trial. The parallels between Ohio Bell and the instant proceeding are apparent in the specific observations of the Justice which follow:

> The Commission had given notice that the value of the property would be fixed as a date certain. Evidence directed to the value at that time had been laid before the triers of the facts in thousands of printed pages . . . Without warning or even the hint of warning that the case would be considered or determined upon any other basis than the evidence submitted, the Commission cut down the values for the years after the date certain upon the strength of information secretly collected and never yet disclosed. . .the Commission . . .[reported] its conclusion, but not the underlying proofs . . .70/

The Court specified the type of information of which judicial notice could be taken, and the infirmities involved in extending the doctrine to include conclusions reached in industry journals when the conclusions relied upon are not notorious to the community:

69/ Exception No. 2 (R. 11308) of the Petitioner's request for rehearing in this case follows the same line of objection urged in Ohio Bell. Petitioners asserted that the Commission relied on "industry-oriented statistics" which had not been introduced into evidence, that therefore no "party to this case has ever had the opportunity to review the data used in the A.G.A. figures . . .In the absence of proof and opportunity for cross-examination and rebuttal, the blind acceptance by the Commission of the extra-record, self-serving industry statements deprives the consumers of the protection accorded them by the terms of the Natural Gas Act."

70/ 201 U.S. at 301.

> Courts take judicial notice of matters of common knowledge. . . They take judicial notice that there has been a depression, and that a decline of market value is one of its concomitants. . .How great the decline has been for this industry or that, for one material or another, in this year or the next, can be known only to the experts, who may even differ among themselves. The distinction is . . . important in cases where as here the extent of the fluctuations is not collaterally involved but is the very point in issue. . . Here the contention would be futile that the precise amount of the decline in values was so determinate or notorious in each and every year between 1925 and 1933 as to be beyond the range of question . . .No rational concept of notoriety will include these variable elements. . . [T]o press the doctrine of judicial notice to the extent attempted to in this case and to do that retroactively after the case had been submitted, would be to turn the doctrine into a pretext for dispensing with a trial. 71/

The Court concluded that the reliance on such extra-record figures by the Commission worked a denial of due process upon the petitioners, recognizing that such procedures "will never do if hearings and appeals are to be more than empty forms."72/

One of the major arguments advanced by the Commission for the extension of unmodified area rates to pipeline producers is that this treatment will motivate the pipelines to seek out new gas sources. The basis for the Commission's assumption as to the cause of the alleged gas shortage is even more flimsy than its foundation for the assumed shortage. There is nothing in the record or elsewhere upon which it can base its assumption that any present shortages that may be related to insufficient exploration efforts are attributable to past regulatory practices as they relate to pipeline producers. Those answers hopefully may emerge from the current investigations the Commissionis conducting in an effort to bring light to this murky, highly disputed area, which is characterized by sweeping industry allegations and few hard facts.73/

71/ 201 U.S. at 301-304.

72/ 201 U.S. at 303.

73/ See Public Service Comm'n of N.Y. v. FPC, No. 23446 D.C. Cir., June 29, 1970).

Indeed, it is significant that according to the very extra-record material (A.G.A. Report) here at issue the alleged diminution in exploration and development was not confined to pipelines but also extended to the independents which are already subject to area rate regulation. 74/ Moreover, the little data which is in this record demonstrates that the pipelines have achieved a better reserve production ratio than that of the independent producers which are already regulated under area rates. 75/ Hence it is clear that this record does not demonstrate nor permit the inference drawn by the Commission as to the cause and effect relationship between exploration activity and area rate regulation of the production operations of the pipeline segment of the industry. If anything, it shows just the opposite.

74/ R. 11284.

75/ During the period 1940-1965, the producing pipelines maintained fairly consistent reserve to production ratios, at a high level. Staff Exhibit No. 6, page 3, shows that the Group 1 producing pipelines had a 27.9 reserve to production ratio in 1946, based on total company owned reserves, and in 1965 had a 24.2 ratio. This compares with the reserve to production ratio of 32.5 for the total United States in 1946 and 17.5 in 1965. (Id.) See Austral Oil Co. v. FPC, supra, Slip Op. pp. 46-60.

CONCLUSION

WHEREFORE, for the above reasons, as well as those set forth in our initial brief, the Municipal Gas Group requests the Court to set aside the Commission's Opinion Nos. 568 and 568-A as contrary to law and the record in this proceeding.

Respectfully submitted,

Richard L. Curry
Corporation Counsel
Mathias M. Mattern
Assistant Corporation Counsel
for Public Utilities
Bernard Rane
121 North LaSalle Street
Chicago, Illinois 60602

Max P. Zall
City Attorney
City and County of Denver
City and County Building
Denver, Colorado 80202

Charles L. Wheatley Jr.

Charles F. Wheatley, Jr.
William T. Miller
Grace Powers Monaco
2600 Virginia Avenue, N. W.
Washington, D. C. 20037

Attorneys for Petitioners

Of Counsel:
George E. Morrow
Union Planters National
Bank Building
Memphis, Tennessee 38103

Reuben Goldberg
1250 Conn. Ave., N. W.
Washington, D. C. 20036

July 16, 1970

376A

BRIEF FOR INTERVENOR
PIPELINE PRODUCTION GROUP

IN THE

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ILLINOIS, *et al.*, *Petitioners*,

v.

FEDERAL POWER COMMISSION, *Respondent*.

On Petition To Review Orders of the Federal Power Commission

RAYMOND N. SHIBLEY
JAMES J. FLOOD, JR.
1120 Connecticut Avenue, N. W.
Washington, D. C. 20036

WM. WARFIELD ROSS
1320 19th Street, N. W.
Washington, D. C. 20036

Attorneys for Intervenor Pipeline Production Group

June 15, 1970

PRESS OF BYRON S. ADAMS PRINTING, INC., WASHINGTON, D. C.

TABLE OF CONTENTS

TABLE OF AUTHORITIES

* Cases or authorities chiefly relied upon are marked with an asterisk.

* Cases or authorities chiefly relied upon are marked with an asterisk.

IN THE

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ILLINOIS, *et al., Petitioners,*

v.

FEDERAL POWER COMMISSION, *Respondent.*

On Petition To Review Orders of the Federal Power Commission

BRIEF FOR THE PIPELINE PRODUCTION GROUP

COUNTERSTATEMENT OF THE ISSUE PRESENTED

In the opinion of the Pipeline Production Group, the single issue presented in this review is:

Whether the Federal Power Commission is authorized under the Natural Gas Act to apply the same cost-based area rates to natural gas production by pipelines and their affiliates from future-acquired properties, as it is applying with judicial approval to the new gas production of independent producers.

COUNTERSTATEMENT OF THE CASE

In this review proceeding, the City of Chicago, *et al.* ("Municipals") seeks to overturn the Federal Power Commission's ("Commission") decision in Opinion No. 568, issued October 7, 1969, to establish the rates for natural gas produced by pipelines or their affiliates from future-acquired leases, under the same cost-determined area price ceilings which the Commission applies in regulating the new gas rates of independent producers.

The principal contention of the Municipals in this review is that the Commission is required to utilize the "individual company cost of service" ratemaking method for future pipeline and affiliate production. This same contention was made in opposition to the Commission's application of the area rate method of group pricing to independent producers. However, while the instant proceeding was pending before the Commission, the Tenth Circuit and the Supreme Court upheld the Commission's area rate treatment of independent producers in *Permian Basin Area Rate Cases*,[1] and the Fifth Circuit recently reached the same conclusion in *Southern Louisiana Area Rate Cases*.[2] The Fifth Circuit has also ruled that area rates, once prescribed by the Commission, are applicable to new sales which were not involved in the proceeding even though the seller was not a party thereto.[3]

While the Commission here determined to apply its industry-wide area rates to gas produced by pipelines and affiliates from new leases acquired after the date of decision, October 7, 1969, the Commission has not yet determined whether existing pipeline production will also be

---

1 *Skelly Oil Co.* v. *FPC*, 375 F.2d 6 (10th Cir. 1967), affirmed as to the new gas rates, 390 U.S. 747 (1968).

2 *Southern Louisiana Area Rate Cases, Austral Oil Co., et al.* v. *FPC*, No. 27492, *et al.*, decided March 19, 1970, pending on petitions for rehearing.

3 *Hunt Oil Company, et al.* v. *FPC*, 5th Cir., No. 27,457, decided April 21, 1970.

governed by area rates; this issue is pending in the second phase of the instant proceeding (R. 11282).

Thus, this review does not involve the rate treatment of (1) existing pipeline production or even (2) production from new wells which may be drilled on leases acquired prior to October 7, 1969. In other words, all of the gas currently being produced or which may in the future be produced from leases already acquired continues subject to the same standards as have been applied in the past until such time as the Commission decides the method which should be used to regulate such production.

In prescribing the area rate method for future acquired leases subject to this proceeding, the Commission has required pipelines and their affiliates to segregate on their books all costs associated with any new leases they may acquire, and to eliminate those costs from any rate proceedings involving gas production from the new leases, substituting therefor the area price which the Commission determines under its group costing method for gas of the same grade and quality (R. 11293).

It is apparent that existing pipeline rates could not be affected by the Commission's action, and that its future impact will be limited to rate proceedings of those pipelines which do in fact both acquire future leases *and* obtain production therefrom.

The Pipeline Production Group, Intervenors herein, consists of thirteen pipeline companies which were made respondents by the Commission in the proceedings below.[4] Of these, six companies are pipeline producers, four pur-

[4] This brief is submitted on behalf of the following individual companies which comprise the Pipeline Production Group: Cities Service Gas Company, Colorado Interstate Gas Company, Kansas-Nebraska Natural Gas Company, Lone Star Gas Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, Southern Natural Gas Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, Trunkline Gas Company, United Fuel Gas Company, and United Gas Pipeline Company.

chase gas from affiliated producers, and three are not engaged in production activities at this time. They participated as a group in the hearings before the Commission to assist in the development of an effective method for regulating future pipeline production, which in turn would allow pipeline producers an opportunity to explore for, develop and produce new natural gas reserves in competition with other producers now under area rates.

From the inception of the Natural Gas Act under which pipeline rates became subject to regulation, there has been substantial controversy over the most appropriate method to be used in pricing the portion of the gas produced by the pipeline itself—but not as to the Commission's power to employ some method other than individual company cost of service, since the Supreme Court early held that the Commission is authorized to use any rational method it selects, *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944). Controversy concerning the most appropriate ratemaking method for gas production was heightened from 1954, when the Commission became obliged to regulate the rates of independent producers as well as pipeline producers, until 1960 when the Commission first adopted the area rate approach. During the intervening years, the Commission undertook to apply individual company cost of service treatment to both independent producers and pipeline producers. See, e.g., *Bel Oil Corp.* v. *FPC,* 255 F.2d 548 (5th Cir.), *cert. den.* 358 U.S. 804 (1958).

The Commission's 1960 policy determination to apply a cost-based area rate method to producers generally, was the outgrowth of its unsatisfactory experience, both administratively and from the substantive standpoint of using price as a vehicle to provide adequate supplies without unnecessary cost to consumers. Its decision to proceed with the area rate method was reached in *Phillips Petroleum Company,* a proceeding which was conducted on an individual company cost approach. The Commission's regulatory objectives were to establish ceiling prices "in all producing

areas which will be adequate to maintain gas supplies . . . at prices that are no higher than necessary . . .[5] "

Implementation of area rate regulation was initiated by the adoption of a *Statement of General Policy,* No. 61-1, 24 FPC 818 (1960) which subdivided the country into producing areas and established guideline prices for the gas production in each area. These area rate levels carried forward the Commission's decision in *Phillips, supra,* that the "better method" of regulation is "to establish fair prices for the gas itself and not for each individual producer." 24 FPC at 547.

As here, the Commission's efforts to implement area rate regulation for independent producers were contested at every stage. Indeed, this Court is familiar with part of this litigation as it sustained the Commission's decision to commence area rate regulation in *State of Wisconsin* v. *FPC.*[6]

Initiation by the Commission of area rate regulation for independent producers in 1960 presented the obvious question whether this method should not also be applied to pipeline production. In April 1961, immediately following the institution of the first area rate proceeding relating to the Permian Basin, an unanimous Commission stated in *Panhandle Eastern Pipe Line Company,*[7] that instead of the individual company cost of service method:

> "We think that a new approach is necessary for the pipeline producers as well as the independent producers."

In the subsequent review of that rate determination, the Commission explained to the Supreme Court:

> "The statement that 'a new approach is necessary for the pipeline producers as well as the independent pro-

[5] 24 FPC 537, 547 (1960), aff'd. *sub nom. Wisconsin* v. *FPC,* 373 U.S. 294 (1963).

[6] 112 U.S. App. D.C. 369, 303 F.2d 380 (1961), aff'd. 373 U.S. 294 (1963).

[7] 25 FPC 787 at 794.

> ducers' refers, of course, to the *area price method* of regulating rates of independent producers upon which the Commission had embarked in September 1960 . . ." (Brief in Opposition, No. 614, October Term, 1962, page 11).

As the Commission's first area rate proceeding, involving the Permian Basin area neared a conclusion, the Commission, on June 24, 1964, included the question whether area rates should be applied to pipeline and affiliate produced gas, as an issue in the *Hugoton-Anadarko* area rate proceeding. The cost data gathered for that and all subsequent area rate proceedings included the responses by pipelines and affiliates to the All-Area Questionnaire, which serves as the principal source of data as to existing production of all classifications of producers (R. 63; 244; 11286).

The Commission staff was unable to prepare its evidence as to the pipeline aspect of the proceeding within the time prescribed, and this together with the limited area there involved, led to the initiation of the instant nationwide *Pipeline Production Area Rate Proceeding,* which was instituted by an order issued April 13, 1966, in Docket No. RP66-24 (R. 7110).

In addition to the parties which have intervened in the present court review, the proceeding below involved active participation by numerous independent producers, distributors and state regulatory commissions.[8] The first step in the new proceeding was to develop a supplemental questionnaire to accumulate any data from pipelines and affiliates which any of the parties desired for purposes of preparing their evidence. These extensive materials were composited by the Commission's staff and along with the All-Area Questionnaire responses for pipeline, affiliate, and

---

8 Among these parties were the state regulatory commissions of New York, Wisconsin and California, frequent champions of the consumer interest. None of them has sought court review nor supported the efforts of the Municipals to overturn this Commission decision.

independent producers, served as the primary source for evidence during the lengthy hearings which ensued (R. 272-3).

Following completion of the extensive evidentiary presentations the Commission's examiner issued an initial decision dated March 3, 1969. The examiner failed to adhere to the Commission's requirement that the instant phase of the proceeding be limited to the rate treatment of future-acquired leases. The basic issue to be determined, under the Commission's order was (R. 7113):

> "What is the most appropriate pricing method to be applied to natural gas utilized in a pipeline's interstate system which is produced by a the pipeline or its affiliated producing company from leases acquired after the date of determination of this issue?"

The Commission had explained its reason for so limiting the issue to future-acquired leases, in the following manner (R. 7113):

> ". . . it would appear that many of the most difficult evidentiary and policy problems can be avoided or at least deferred if, in any separate proceeding on pipeline production costing, consideration is initially limited to a determination of whether pipeline produced and self-consumed gas on leases acquired after the date of any final Commission policy determination—by rule or otherwise—should be priced on an area basis and, if so, the exact nature of such area rate."

It was apparent from the outset that the Commission intended to focus solely upon the regulatory treatment of future-acquired gas from entirely new leases. Of course, in an extensive hearing of this type it would have been virtually impossible, and certainly cumbersome, to attempt to exclude all evidence concerning past production, reserved for decision in Phase II. Much evidence was presented concerning the old, or flowing gas—particularly the testimony sponsored by the Municipals which they cite in their brief here as support for various statements made by the examiner in his decision.

It would be diversionary to undertake a discussion of the examiner's handling of the evidence relating to existing pipeline production, since that subject is not involved in this review. As to the future, although the Examiner found that there is a need for increased pipeline production and that the traditional formula should be changed in order to ameliorate the competitive disadvantage being experienced by pipeline producers (R. 10115-7), he felt constrained to recommend only an "interim" solution. The interim solution provided only partial relief, was of questionable legality, and would have been utterly impossible to administer.[9]

Based upon its own analysis, as well as those findings of the examiner relating to future leases for which there was any evidentiary support (R. 11361), the Commission, after full briefing and oral argument, reached a decision to apply its area ceilings to future pipeline production from later acquired leases (R. 11292-3). The Commission's action is designed to foster additional gas supplies and to make its area pricing program applicable to all new gas. But since there is a time lag between new lease acquisitions and the development of significant production from those new leases, the Commission's decision achieved the examiner's stated objective by automatically precluding the possibility of increased pipeline rates within the near future, while at the same time protecting against the upward thrust which would have been introduced by applying individual company cost of service methodology to future gas production (R. 11360).

This consumer protection, achieved by the Commission's adoption of area price ceilings for future acquired pipeline and affiliate produced gas, is at least three-fold. First, the

[9] The examiner's "interim" proposal was designed largely to avoid any immediate impact on rates charged by pipelines to their utility customers, a result also reached by the Commission but without the attendant disadvantages of the examiner's unworkable proposal. The inappropriateness of the examiner's "interim" solution is attested by the fact that no party to the proceeding below supported or accepted his recommended decision.

Commission's action now precludes pipelines from charging ratepayers for produced gas, a price higher than the area price in those instances in which pipeline producers will incur costs above the industry average (R. 11284). Such increased costs would likely have become more prevalent if individual cost of service pricing had been extended to future leases, especially since recently developed pipeline production under the prior ratemaking principles has "in the main led to high-cost gas" (R. 11283).

The second immediate cost benefit to consumers flows from the application of area price ceilings, rather than the higher costs actually incurred by some pipeline in purchasing semi-developed or developed fields or leases. Absent special circumstances, the burden of proof of which will now be on the pipeline, the ratepayers will henceforth be shielded from this type of cost (R. 11285; 11360-1). Similarly, acquisition by pipelines of developed leases from which gas is already flowing, will also henceforth be priced at the area rate (or contract price, whichever is lower) rather than at the higher cost level which invariably results from individual cost of service treatment of such production (R. 11290-1).[10]

The third significant cost savings to consumers as a whole results from the economic incentive, heretofore largely lacking, to increase productivity and efficiency in exploration and development of pipeline owned gas (R. 11285). This will redound to the benefit of the ratepayers through lessening aggregate industry costs upon which future area rates will be based.

Apart from the specific cost benefits which the Commission found would be achieved for consumers through apply-

---

[10] In both instances the cost savings to ratepayers should be substantial, as much of the increased pipeline investment in production properties has been incurred through their purchasing leases or fields discovered and developed by others, which their original owners were quite naturally unwilling to sell except at a price greater than the revenues which they could derive from area rates through retention and normal production of the leases (R. 584; 2341).

ing its area pricing method to future-acquired pipeline and affiliate production, even greater benefits are likely to accrue through increased availability of supply resulting from renewed pipeline and affiliate exploration and development efforts (R. 11284; 11360).

In the context of eliciting adequate supplies which heretofore have not been achieved, the dichotomy between the area price ratemaking method and the individual company cost of service method is particularly sharp. By definition, area rates for *new* gas (as distinguished from flowing gas) are required to be fixed at levels designed to elicit from the producing industry, the quantum of supply found by the Commission to be in the public interest. *Southern Louisiana Area Rate Cases, supra,* slip opinion, page 13.

On the other hand, the individual company cost of service method—regardless of its lawfulness if prescribed by the Commission—is not, and never has been, predicated on the concept that it would *increase* production; rather, its asserted premise is that it simply compensates for past expenditures. And the facts are, as found by the Commission, that pipeline production has steadily but significantly declined under the individual company cost of service method (R. 11284; 11359; 665-66; 5888; 5890). The Commission's understandable preference for a ratemaking method more responsive to the public's need for adequate supplies provides additional support for its decision here.

Finally, as indicated by the Commission, the cost-based area rate for new gas, which it here deemed applicable to new pipeline and affiliate production from future leases, is established by a formula which utilizes the costs of pipelines and affiliates as well as independent producers (R. 11286; 2097; 4500-4), and is, therefore, entirely appropriate for pricing of the gas involved in this proceeding. The area rate levels for new gas are, of course, established in specific area rate proceedings, in which all parties, including the Municipals, presumably will continue to participate, as they have in the past.

ARGUMENT

I.

AREA RATES FOR FUTURE PIPELINE PRODUCTION ARE LEGALLY PERMISSIBLE UNDER THE NATURAL GAS ACT

The major portion of the argument presented by Municipals consists of a lengthy compendium of citations to the effect that the individual company cost of service method has been applied rather consistently by the Commission in regulating pipeline production, and the Commission's use of that method has received judicial sanction (Brief, pp. 15-29; 39-42). Their argument is largely superfluous, for the question presented in this review is not whether the method previously applied to existing production is lawful. Rather, the issue is whether it is unlawful for the Commission to employ the area rate method in pricing production from future leases of pipeline and affiliate producers. With deference, we submit that the Municipals have almost entirely avoided this overriding issue.

This section of the Pipeline Production Group's brief undertakes to demonstrate the legal basis for area rate regulation. We then show that this method may be lawfully applied to the future production of pipeline and affiliate producers; that the Commission is not precluded from changing its rate-making method; that the Commission's findings in support of area ratemaking for future pipeline production are entirely adequate; and that Municipals have failed to discharge their heavy burden to show that the Commission's prospective policy is unjust and unreasonable.

A. The Validity of Area Ratemaking Is Firmly Established

Despite the fact that the individual company cost of service method of rate regulation had been used by the Commission extensively in its rate determinations for pipeline producers as well as independent producers, the Commission's adoption of cost-determined area rates has been fully sanctioned in every judicial review proceeding in

which it has been tested. *Wisconsin* v. *FPC,* 373 U.S. 294 (1963); *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968); *Southern Louisiana Area Rate Cases Austral Oil Co. et al.* v. *FPC,* 5th Cir., No. 27,492, *et al.,* decision issued on March 19, 1970.

In each of the foregoing cases, the Commission's adoption or use of area ratemaking was attacked on the premise that individual company cost of service regulation is required by the Constitution and the Natural Gas Act.[11] This notion was emphatically rejected by the Supreme Court in *Wisconsin* v. *FPC, supra,* at 309, the case in which the Commission first determined to apply area ratemaking:

> "More specifically, the Court has never held that the individual company cost of service method is a *sine qua non* of natural gas rate regulation . . ."

The Commission proceeded with area rate regulation and in 1965 issued its first decision establishing just and reasonable rates for all gas production from an area known as the Permian Basin, clearly explaining the purposes and objectives of area rate regulation as follows (34 FPC 159, 179):

> "A uniform area pricing system is adapted to the economics of the natural gas industry. The producer who finds large reserves will achieve greater profits than the producer whose exploration efforts result in dry holes or marginal wells. Likewise, the producer whose enterprise is conducted with efficiency and economy will make more money than the producer who runs his business poorly. There is a strong incentive in area pricing to prudence and economy which does not exist in individual company cost-plus pricing in an industry where individual cost norms are difficult to determine and apply. *True, individual returns will vary greatly, but this is as it should be, provided that profits in the aggregate are at a reasonable level.*

[11] Act of June 21, 1938, c. 556, 52 Stat. 821-833, as amended, 15 U.S.C. 717-717w.

> "The area regulatory pattern thus confirms to the characteristics of an industry which, as much as any, is one where there is scope for greater or lesser reward as dictated by the results of exploratory efforts. *The area price will give producers the incentive they need to explore to meet the nation's increasing demand for natural gas and yet give consumers the protection which the Act intended."* [Emphasis added]

The Commission's authority to prescribe area rates for production activities was recently upheld by the Supreme Court in *Permian Basin Area Rate Cases, supra.* The Court enunciated the Constitutional and statutory basis for area rate regulation, holding first that the legislative power under the Constitution to establish maximum price ceilings has been "customary from time immemorial", citing *Munn* v. *Illinois,* 94 U.S. 113, 133, (1887) and noting that the Court has sanctioned such power whenever the issue has been raised. The Court also expressly refused to construe Sections 4 and 5 of the Natural Gas Act as requiring individual company rates. Lastly, the Court concluded that area rates are consistent with the Natural Gas Act, holding (390 U.S. at 775):

> "The Court in *Hope* emphasized that we may not impose methods of regulation upon the Commission; for purposes of judicial review, the validity of a rate order is determined by 'the result reached, not the method employed.' 320 U.S. at 602, 64 S. Ct. at 287, see also *FPC* v. *Natural Gas Pipeline Co., supra,* 315 U.S. at 586, 62 S. Ct. at 743. The Court there did not reject area regulation; it repudiated instead the suggestion that courts may properly require the Commission to employ any particular regulatory formula or combination of formulae."

More recently, the United States Court of Appeals for the Fifth Circuit again upheld area rate regulation in reviewing the just and reasonable rates established for the

Southern Louisiana area.[12] *Southern Louisiana Area Rate Cases, supra.* Stating that "the Commission must have latitude to adapt to changing conditions" (slip opinion, page 3), and rejecting the contention that area pricing is "too imprecise to be used in regulating the gas-producing industry," the Fifth Circuit expressly affirmed "the use of average rather than individual producer costs" (slip opinion, pages 40-1):

> "Similarly, the producers make a broad attack on the use of average, rather than individual producer costs. We reject this attack as the Supreme Court rejected it in *Permian.* There is nothing in either the Constitution or the Natural Gas Act that prevents the Commission from adopting price ceilings under which some producers will make more money than others or even under which some producers may be in danger of going out of business." [footnote omitted]

Since it is now incontestable that area rates can be validly applied to production activities, we turn to the Municipals' contention that the Commission is precluded from employing this method for pipelines and affiliates.

B. The Commission Is Not Restricted to Any Single Ratemaking Formula for Pipeline Production

The underpinning of the Municipals' attack upon the Commission decision to apply area ratemaking to future-acquired pipeline and affiliate production is the mere historical fact that another method has previously been used. At one point the Municipals even contend that "deviation" from the individual company cost of service method "may be impermissible without amendment of the Natural Gas Act" (Brief, pp. 39-42).

---

12 Southern Louisiana is the most important domestic gas producing area (slip opinion, page 11). At this time, area rate proceedings establishing just and reasonable rates have been completed in producing areas accounting for almost 93% of the gas sales volume under the Commission's jurisdiction. (Federal Power Commission, 1969 Annual Report, page 55).

This novel contention is sought to be supported by the citation of only two cases, *City of Detroit* v. *FPC*,[13] and *Colorado Interstate Gas Co.* v. *FPC*.[14] This argument is patently frivolous for in *City of Detroit* this Court stated, "we hold that method not to be the only one available under the statute" (230 F.2d at 818); and in *Colorado Interstate*, the Supreme Court held (324 U.S. at 601):

> "We do not say that the Commission lacks authority to depart from the rate-base method. We only hold that the Commission is not precluded from using it."

In the second *Phillips* case, this Court went further, not only permitting departure from the traditional rate base method, but also sanctioning the commencement of area pricing as the method for establishing producer rates. *State of Wisconsin* v. *FPC, supra.* The Supreme Court, in affirming, expressly stated that it does "not interpret the decision of the Court of Appeals in *Detroit* v. *Federal Power Commission* . . . to suggest that, in the view of that court, individual cost of service is the method required to be used in independent natural gas producer rate regulation." Then, referring to this Court's pronouncement concerning the use of cost of service as a point of departure in pricing pipeline produced gas, the Supreme Court said (373 U.S. at 310):

> "Whatever the court may have meant in that context, it is clear that it did not have before it any question relating to the area rate method, and it is interesting to note that Judge Fahy, the author of the Detroit opinion, said in his opinion below in this case: 'We should not seek to deter the Commission from pursuing such a method [the area method] in future proceedings already initiated along these lines.' "

Similarly, in the *Permian Basin Area Rate Cases, supra,* the Supreme Court reaffirmed the Commission's authority

---

13 97 U.S. App. D.C. 260, 230 F.2d 810 (1955), *cert. den.* 352 U.S. 829 (1956).

14 324 US. 581 (1945).

to change its regulatory policies in prescribing rates for natural gas production, stating that the Commission "must be free, within the limitations imposed by pertinent constitutional and statutory commands, to devise methods of regulation capable of equitably reconciling diverse and conflicting interest" (390 U.S. at 767).

And, finally, this Court has recently stressed the necessity for the Commission to revise its policies and methods when it sees the need for such action. In *City of Chicago* v. *FPC*, 385 F.2d 629, 637 (1967) *cert. den.*, 390 U.S. 945 (1968), the Court explained that:

> "The Rule of Law does not forbid an agency from modifying its regulatory policy, and the courts have upheld policy revision many times. Indeed one of the signal attributes of the administrative process is flexibility in *reconsidering and reforming of policy.* What is required by the Rule of Law is that agency policies and standards, whether or not modifications of previous policies, be reasonable and non-discriminatory and flow rationally from findings that are reasonable inferences from substantial evidence." [footnote omitted, emphasis added]

It is apparent from the foregoing that the area rate method is an entirely valid means for establishing the amount which can be charged for produced gas, and that the Commission is authorized to change from the individual company cost of service method to the area rate method if it has a rational basis for doing so. Clearly, such a basis exists here, as we now show.

II.

THE COMMISSION'S FINDINGS FULLY SUPPORT THE PROSPECTIVE APPLICATION OF AREA RATES TO PIPELINE PRODUCED GAS

Having extensively developed, in its area rate proceedings, both the methodology and the levels of just and reasonable rates for produced gas, the Commission is thoroughly equipped to determine whether those principles are applicable to prospective findings of gas by pipeline and affiliate producers. As set forth in its decision, the

Commission carefully evaluated all factors pertinent to this determination. Its findings satisfy the legal standards for prospective change in regulatory policy and are fully supported in the record.

The Commission's area ratemaking procedures sharply distinguish between old or flowing gas—production from existing wells—and new or prospective gas not yet found or committed to any market. *Southern Louisiana Area Rate* Proceeding, 40 FPC 530, 551, 556 (1968). Since the Commission has limited its determination here to prospective supplies, indeed supplies from leases acquired subsequent to the date of its order, the treatment of existing production was entirely unaffected by its decision (R. 11282). The standards to be applied, therefore, involve the applicability of the Commission's court-approved new gas principles to like supplies which will be developed in the future by pipeline and affiliate producers.

The Commission's threshold inquiry, characteristically, was whether failure to apply area price ceiling restrictions to pipeline produced gas could be reconciled with the public interest (R. 11283). The Commission concluded that it would not be in the public interest to permit ratepayers to be charged substantially higher prices for future gas supplies produced by pipelines or affiliates than for similar gas obtained from independent producers (R. 11285-6).

Finding that the present cost-of-service methodology permits indifference to cost considerations and tends to put a premium upon high cost operations (R. 11285),[15] the Com-

---

[15] Dr. M. J. Peck, a former member of the President's Council of Economic Advisers, went to the heart of this matter, stating (R. 695-6): "The producer can affect these costs by his own choices between purchased gas and his own production. To insure these choices are made efficiently the spur of losses for poor choices and the carrot of above-median rewards for good management is needed. Otherwise, for example, the consumers might have to pay the higher costs where the pipeline undertakes production activity as a matter of preference rather than to minimize costs. Cost-of-service regulation is also inconsistent with encouraging efficient exploration. The higher costs of an inefficient operation would tend to be shifted forward to the consumer and absent a penalty for inefficiency, the general level of efficiency would be lower than under some system where the producers would be penalized for bad choices and inefficiency."

mission concluded that under its decision the public will henceforth be "protected by the area rate concept from bearing the brunt of the unsuccessful or otherwise unnecessarily high-cost pipeline production efforts" (R. 11287).[16] In other words, only the area rate method would impose a predetermined ceiling on the amount the pipeline producer can pass on to ratepayers.

The Commission then turned to the dual questions, (1) whether new supplies of pipeline and affiliate production would be in the public interest if priced at a cost-based rate applicable to new gas supplies in each area, and (2) whether area rates would permit pipelines and affiliates to join in the search for new gas supplies in competition with independent producers under area rates.

As to the first point, the Commission found that, despite the fact that pipeline produced gas is a desirable adjunct to supplies they purchase from independent producers, there has been a pronounced decline in pipeline exploration and development of new reserves under the previous rate-making method (R. 11284).[17] Apart from the special benefits accruing to pipelines from ownership of their own supplies (R. 717-8), the Commission further found that it would be desirable to encourage intensified exploration by pipelines and affiliates because of the greater assurance that

---

[16] The record demonstrates that under cost of service treatment of company-owned production, a disproportionately large number of pipeline producers conducted high-cost production operations (R. 5908-10; 674). One-half of the pipeline and affiliated producers incurred unit costs in their production operations in excess of the industry average; in contrast, only 30 percent of the independent producers incurred unit costs above the industry average (R. 5908-10), and of these, none would be permitted to charge a price above the area rate.

[17] The Commission was also aware of the fact that much of the recent additions to pipeline produced gas supplies resulted from in-place acquisitions of already developed, "and hence more expensive leases" (R. 11285). This is borne out by the record (R. 687; 904; 1705; 2334-7; 4100). Under the Commission's decision, the consumer will no longer bear the higher cost of this type of arrangement in future transactions (R. 11290-1).

gas reserves so discovered will be promptly dedicated to the interstate market so as to provide adequacy of supply for consumers (R. 11290).[18]

The Commission was entirely justified in seeking to encourage more aggressive exploration programs, both by pipelines and others, especially in view of the current shortage of gas in the nation generally (R. 11281; 11284). We deal elsewhere with the Municipals' criticism of the Commission's reference to the gas shortage. But, given the Commission's paramount responsibility in this field and its intimate knowledge of gas supply conditions, it would be most astonishing if the Commission were to ignore a problem of this magnitude in selecting its regulatory method for pricing of future supplies of gas.

It is true, of course, that the Commission cannot guarantee that pipelines will engage in significantly greater production activities under the area ratemaking method (R. 11360), a matter which must necessarily depend to some extent upon the rate levels prescribed in the general area rate proceedings. However, a principal function of the new gas area rate is to elicit the desired level of gas supplies, as the Commission and the courts have repeatedly recognized in the area pricing decisions.[19] By providing the pipelines and affiliates with this "predetermined cost allowance" along with the independent producers, the Commission reasonably concluded that its supply-eliciting expectations would be fulfilled (R. 11360). Moreover, to accomplish this objective, the efforts of all will be required (R. 719-20).

---

[18] Under area rates, the new gas price is applicable only to gas committed to the interstate market (34 FPC at 186). In *Permian Basin*, the Commission and the examiner found that the industry had developed the ability in recent years, to direct its exploratory search selectively for gas, rather than hydrocarbons in whatever form—"a breakthrough [which] affords an opportunity for a new approach" (34 FPC at 335).

[19] *Skelly Oil Co.* v. *FPC*, *supra* at 24; *Southern Louisiana Area Rate Cases*, *supra* (slip opinion, pages 13-14).

The Commission's decision to adopt group pricing for pipeline and affiliate producers, rather than individual cost of service rates, is well within the principles established by the courts. In *Permian Basin Area Rate Cases, supra,* the Supreme Court held (390 U.S. at 769):

> "This Court has repeatedly recognized that legislatures and administrative agencies may calculate rates for a regulated class without first evaluating the separate financial position of each member of the class; it has been thought to be sufficient if the agency has before it representative evidence, ample in quantity to measure with appropriate precision the financial and other requirements of the pertinent parties."

As the Commission explained in its *Permian* and *Southern Louisiana* decisions, new gas exploration and development is nationwide in its scope (34 FPC at 191; and 40 FPC at 559-60). Consequently, it is necessary to measure the aggregate financial requirements for all producers engaged in finding new gas reserves on a nationwide basis (R. 2332, 2448). The new gas ceilings which govern gas sales in the major producing area are anchored to these nationwide finding and development costs (R. 11284). The Commission's new gas area rates relate the current cost of finding new reserves on a nationwide basis to the reserve additions achieved by such expenditures. The cost experience is derived from *all* producers (R. 2332, 2448, 2784). As the Commission stated in *Permian Basin* (34 FPC at 191):

> "A [new gas] price based on the current cost of finding and producing a Mcf of gas-well-gas . . . should provide the economic incentives to find and sell gas under prevailing conditions at rates which are keyed to industry needs and at the same time to protect the interest of consumers."

Moreover, as the Fifth Circuit observed in its recent decision in *Southern Louisiana Area Rate Cases, supra,* "new gas is priced to allow for the appropriate level of

exploration, and the Commission determined that exploration for gas was and should be undertaken on a nationwide basis, so new gas costs are based upon present cost for the entire nation" (slip opinion, page 13).

Essentially, the Commission's new gas cost is a cross-section of the present or current cost to find, develop and produce a thousand cubic feet of natural gas on a nationwide basis (R. 2332; 2448; 2784). This may be contrasted with the area rates for old, or flowing, gas—not in issue here—which are "historical area costs", *Southern Louisiana Area Rate Cases, supra,* (slip opinion, page 13).[20]

In reaching its conclusion in the instant proceeding, the Commission relied upon the particular methodology it had earlier prescribed for fixing new gas area rates. These rates are calculated from "industry-wide statistics which included the current production experience of the pipelines" (R. 11286).

Indeed, there is not a single component in the new gas well gas cost estimate—from reserves added to operating expenses—which does not include pipeline cost data (R. 2097). Thus, the new gas cost represents an industry-wide estimate of the cost of finding an Mcf of gas-well-gas for independents, pipelines and affiliates (R. 4500-4). The Commission determined that the cost of finding and producing new gas well gas by pipeline producers will approximate the average cost of all producers (R. 11286; 11361-2), and there is substantial evidence to support this finding (R. 5906; 673; 683). It rationally follows that the new gas area cost also measures the financial and other requirements of the pipeline producers as a group.

This conclusion is further buttressed by the Commission's finding that there is no basic distinction between the

---

[20] Based on historical cost levels, the Commission found that "pipelines as a group had per Mcf costs significantly higher than those of independent producers" (R. 11285-6; 2206-7), but as to future gas operations under area rates, the pipeline and affiliate producers will approximate the costs of all producers (R. 11286), a conclusion shared by the examiner (R. 10118).

exploratory and production operations of pipeline producers and other producers (R. 11361). Pipeline and affiliate producers have conducted their operations in all of the production areas established by the Commission (see e.g. R. 5758). All producers must acquire leases, conduct geological and geophysical operations and drill exploratory wells in order to find and develop gas reserves (R. 711; 715). Pipeline producers must employ the same geological and geophysical techniques, buy the same types of drilling and other equipment, and use the same contractors in finding and developing new gas reserves, as any other producer (R. 637-53; 3061). Lastly, pipeline producers and independent producers are increasingly engaging in joint production ventures which tend to equalize their cost experience (R. 647-8; 670-2; 710; 3060-1; 3086-9; 5899-5904). There is thus no rational basis for disparate rate treatment for future vintages of gas.

Since the determination as to regulatory treatment of future pipeline production is peculiarly within the Commission's competence, the Commission's carefully prepared decision based on ample evidence, should be affirmed.

III.

PETITIONERS HAVE FAILED TO DEMONSTRATE THAT AREA RATES FOR FUTURE PIPELINE PRODUCTION ARE UNJUST OR UNREASONABLE

The policy decision to apply just and reasonable area rates, rather than individual company cost treatment, to future pipeline production was made after the decade of regulatory effort required to implement area rate regulation. It was in accordance with the Commission's conclusions in the *Permian Basin Area Rate Proceeding* that (1) cost standards for gas production "can be best developed by examining overall producer experience"; (2) uniform area prices are "adapted to the economics of the natural gas industry"; (3) prices fixed by individual company costs might either be too high or too low for consumers "in rela-

tion to other available supplies"; and (4) area rate regulation is administratively feasible (34 FPC at 179).

Petitioners have a "heavy burden" to make the convincing showing required by the Supreme Court, first in its *Hope* decision and later in *Permian Basin Area Rate Cases,* that the Commission's decision to apply an approved regulatory method to all producers "is invalid because it is unjust and unreasonable in its consequences." 320 U.S. at 602. This burden is not discharged by simply arguing that some other method—such as individual company cost of service—is also lawful. The Commission is certainly authorized to select which of two lawful methods should be applied under current circumstances, and on the basis of this record. *Alabama-Tennessee Natural Gas Co.* v. *FPC,* 359 F.2d 318 (5th Cir.) *Cert. den.,* 385 U.S. 847 (1966).[21]

It is simply not true that the administrative proceedings below were "merely a replay" of the 1954 decision involved in the *City of Detroit case, supra* (Brief, pages 25-6). For example, the evidence here demonstrates that the unit cost of new gas for pipeline producers under the Commission's formula is not essentially different from the industry-wide new gas cost used in the area rates (R. 5906; 673; 683).

Not only that, but as the Supreme Court observed in second *Phillips,* the *City of Detroit* case did not involve the area rate method in any respect (374 U.S. at 310, n. 16). Rather, it dealt with "field price . . . based upon the 'weighted average arm's length prices' established by fed-

---

21 The court cited with complete approval the position of the Solicitor General in the Supreme Court (359 F.2d at 335, n. 34):

"... From this survey, it appears that, whatever merit there may be in either method, the least that can be said is that a regulatory commission's choice between the two [normalization or flow-through] is assuredly within its discretion, depending on the particular views of the particular agency. *No general issue of law is involved,* only a discretionary choice among competing accounting systems. Such a choice is not one which warrants review by this Court. *Under the same principle, the choice is one which can be changed by the Commission should it become convinced that the other method is preferable.*"

erally unregulated bargaining for similar gas in the fields" (230 F.2d at 813). Here, the applicable area rates are cost-predicated just and reasonable rates. As the Commission found:

> "If pipelines, by moving to an area rate technique, can be encouraged to increase their activity in the search for and production of gas without increasing the overall cost of the gas to the consuming public, this certainly should be encouraged. And assuming, *arguendo,* the continuing applicability of the dictum of *City of Detroit* v. *FPC,* 230 F.2d 810 (CADC 1955), certiorari denied, 352 U.S. 829 (1956), clearly the 'anchor' the court there felt should be the 'point of departure' in moving to a pricing system other than the conventional rate-base method (*ibid.* at 818-819) lies in the approved just and reasonable area rates for independent producers."

A. Indivisibility of New Area Rate

The just and reasonable area rates for producers, of course, involve the multi-price system which "affords the Commission the best opportunity to provide necessary incentives for continued exploration for future gas while avoiding excessive prices for gas already dedicated." *Southern Louisiana Area Rate Proceeding, supra,* 40 FPC at 551. The new gas price which is now to be applied to pipeline producers, is not a series of fragmented components, but rather a single unit amount designed to accomplish the Commission's supply elicting objective. The Commission's explanation in its *Permian Basin* decision is as follows (34 FPC at 186):

> "In referring to the incentive provided by the ceiling for 'new' gas-well gas *we are not providing any special, isolated amount as a separately designated incentive.* The inducement to be found in the 'new' gas price is of an *inherent nature and is not represented by any sum earmarked for that purpose. The incentive is built into the two-price system.* It provides a price for the future related to current and future costs and payable

> only to producers who discover gas-well gas and dedicate their discoveries to the interstate market." [Emphasis added]

Municipals completely misconceive the nature and function of the new gas area rate when they seek to overturn the instant decision by challenging the applicability to pipeline producers of one or two components of the overall rate. Their contentions concerning the rate of return aspect (Brief, pp. 45-50) as well as the federal income tax aspect (Brief, pp. 51-56) of the area rate are manifestly defective in this regard.

It is not permissible to subdivide, or dissect, the unit area rate to determine its applicability in establishing rates for a particular company or group of companies substantially less than the entire industry, and especially so when other components of the total rate are known to deviate in the opposite direction when compared to the particular company or group of companies (R. 2331). For, as the Commission noted, other costs of pipeline producers might be expected to be above average (R. 2206-07; 11286).

In a similar vein, the Commission rejected a compartmentalized analysis of the area rate involved in *Union Texas Petroleum, et al.*, 41 FPC 453 (1969) in the following language, which is equally applicable here:

> ". . . Taxes are but one component of price. Much of the purpose of the in-line proceedings required by the Supreme Court in *CATCO, Atlantic Refining Co.* v. *Public Service Commission of N.Y.*, 360 U.S. 378 (1959), would be vitiated were we to have utilized a compartmentalized in-line proceeding, setting in-line rates separately for each segment of cost. The protection of consumers, as recognized by the Court of Appeals for the Ninth Circuit in *United Gas Improvement Co.* v. *FPC*, 283 F.2d 817 (C.A. 9, 1960), certiorari denied sub nom. *Superior Oil Company* v. *United Gas Improvement Co.*, 365 U.S. 879 (1961), can be accomplished only by looking to the total price, not by artificially separating out various segments thereof."

1. Rate of Return Composite

Apart from the overriding mistake implicit in attempting to fragment selectively the area rates which have been established in industry-wide rate proceedings, the Municipals have committed the further error of comparing factors which are used for radically different purposes. The 6 to 6.5% rate of return which Municipals contend is applicable to pipeline production properties cannot be analogized to the 12% rate of return employed by the Commission in arriving at the unit area rate level for new gas.

The so-called pipeline rate of return—which now substantially exceeds 6 to 6.5% of course—is applied to a conventional rate base consisting of property used and useful in pipeline operations. In contrast, the base to which the new gas area rate of return is applied is a hypothetical average quantity. 40 FPC at 569. Unless the pipeline company's investment in future production property happened by chance to coincide with the average for the industry, the use of the area rate could not be said to yield the full production return (R. 4512).

Moreover, the return component of the new gas cost is also derived from an assumed average production life, so as to yield a return on one-half of the capital expenditure. It is thus a return projected on a future, rather than a past investment as in the case of the traditional utility rate of return. Also, the unique concept of the area rate of return for new gas is based entirely upon the assumption that the future reserves will be depleted in equal annual amounts over a 20-year period, whereas production rates experienced by pipelines are substantially slower, as set forth elsewhere in the Municipals' brief (p. 32).

There is, moreover, no possible basis for the argument that pipelines will "at least double the return on equity" if their produced gas is priced at area rates (Brief, p. 47). A pipeline transmission rate of return, including the equity portion thereof is, in theory, at least, a guaranteed return

on test year investment. On the other hand, the area price level is intended to provide only an opportunity return (R. 1133).

It is sheer sophistry for the Municipals repeatedly to make the unqualified assertion that "area rates for pipeline-produced gas would result in at least double the return on equity (i.e. profit) that the independent producers receive" (Brief, pp. 47; 10, 45; 50), especially when their own policy witness Van Scoyoc testified that under area rates there is no certainty of earning the opportunity return (R. 3654):

> "The rate of return which the Commission used to determine a ceiling price in the Permian Basin case is what you say, on 12 percent. That doesn't mean any individual producer is going to earn 12 percent on his gas sold in interstate commerce."

Under area pricing, the returns earned will vary greatly from company to company, regardless of classification. A producer whose operations are less successful, or more expensive, than the industry average will not earn the opportunity return, because the area rate approach presupposes that shareholders will bear the risk of unsuccessful operations and the gains of successful ones (R. 1113).

In the instant case, the Commission relied on the fact that "the public is protected by the area rate concept from bearing the brunt of the unsuccessful, or otherwise unnecessary, high cost of pipeline production efforts" (R. 11287).[22] This, of course, is exactly opposite from the rate base concept with which the traditional pipeline rate of return espoused by the Municipals is associated. It is apparent,

---

[22] In *Southern Louisiana Area Rate Proceeding, supra*, the Commission made it absolutely clear that "a producer's inability to recover either its unsuccessful exploration costs or the full 12% return on its production investment" would not constitute grounds for special relief. 40 FPC at 615. The Commission has applied exactly the same restriction to the pipeline and affiliate producers in the instant proceeding (R. 11360).

therefore, that the rates of return under the two varying principles cannot fairly be compared in the manner attempted by the Municipals.

In addition to the erroneous premises already exposed, the argument of the Municipals with respect to rate of return is defective for still another reason. The basis for the assertion that pipeline rates of return are lower than that included in the area rate stems from the asserted difference in capitalization between pipelines and independent producers. But, the historic low-cost debt embedded in the capital structures of older pipelines is by definition, and in actuality, already invested in plant, and this sunk investment cannot be used for the *future* exploration and development activities for which area rates have now been prescribed.[23] If new gas exploration can be financed at all through debt, this opportunity is no more available to pipelines than to producers (R. 716).

There is no showing whatever by the Municipals that pipelines can finance future production less expensively than other producers. The Commission, which is certainly well-informed on this issue, so held (R. 11286).[24]

---

[23] The capitalization ratios and debt costs used by the Municipals in their return calculations are, in any event, based upon completely outdated figures from 1962. The evidence shows that during the subsequent four years, through 1966, the debt ratios of the pipelines decreased, while the debt ratios of the independent producers increased (R. 4257-63). This trend is expected to continue (R. 4983). The capital structures of individual pipeline producers are quite varied, as are the capital structures of individual independent producers (R. 6146-7). Like other individual company components, the Commission in the area rate cases does not adjust rates of return for individual variances in capital structures (R. 3655).

[24] The "staggering burden" which the Municipals argue would result from implementation of the instant decision, is grossly misleading. After undertaking to compute the difference between the transmission rate of return and the area rate of return, Municipals have multiplied this fictitious figure by the total volume of gas which was produced by the entire pipeline industry in 1965, and then multiplied the result by 25 years. Patently, the Commission has not applied the area rate to *any* of this flowing gas.

2. Income Tax Composite

In addition to the rate of return argument, Municipals complain that the Commission's order fails to consider the effect of asserted "loss" of potential future spillovers of income tax credits. This item is related to the return argument since the assumed "spillover" represents the amount by which production tax deductions exceed the assumed taxable income from those operations.

Here again, the unfounded argument is advanced that the Commission's action harms ratepayers. The argument is unsupportable because there is no basis whatever for assuming that in the aggregate, the deductions applicable to future production would exceed the applicable taxable incomes of the pipeline producers as a whole. Indeed, the evidence cited by the Municipals (Brief, pp. 55-6) shows that insofar as present production is concerned, there would be no aggregate "spillover" (R. 6160-1).

Municipals also fail to point out that there is no federal or state income tax allowance or component whatever included in the new gas area rates prescribed by the Commission. *Permian Basin Area Rate Proceeding, supra,* 34 FPC at 206-7). Hence, there can be no "fictitious or unreal tax expense" as in *City of Lexington, Kentucky* v. *FPC,* 295 F.2d 109 (4th Cir. 1961), relied upon by Municipals.[25] Since individual producing companies generate

[25] The absence of any income tax component in the new gas area rate would, of itself, preclude a hybrid attempt to apply to pipeline producers (or independent producers) area rate ceilings coupled with individual company tax spillover flow-through. The most likely reason for deductions exceeding taxable income at a given time, would be that the company's drilling program exceeded the industry average. Although substantial drilling programs are to be encouraged, particularly under present day gas shortage conditions, the treatment of production-related taxes on an individual company basis would, ironically, result in a double penalty: (1) the recovery of drilling expenses would be limited to that provided by the area rate level, while tax deductions would exceed the average by reason of the above-average drilling activity; and (2) the portion of the tax deductions resulting from the larger than average drilling expenses would then be used to reduce the individual producing company's rates.

varying amounts of taxable income and tax deductions, the Commission eliminated federal taxes on an industry-wide basis from the area rate. In *Southern Louisiana Area Rate Proceeding,* the Commission continued this practice with the following explanation (40 FPC at 585):

> "Upon consideration of the exhibits as part of the record, we find confirmation of our conclusion that on an industry wide basis there is no support in the record for a finding of an income tax liability attaching to the industry's gas production operations. Again, some of the corporate and individual entities constituting the industry may in particular years pay income taxes. *However, the tax component, like other cost components, must be considered in the context of the industry as a whole. The costs of individual companies are only significant as a part of the overall costs . . .*" [Emphasis added]

Similarly, in its opinion here, the Commission recognizes that "some pipelines paid taxes on their production activities, while others (also like some independent producers) will have tax credits . . .", but consistent with its earlier decisions, concluded that under the area rate method the issue is whether the "industry as a whole on the average" paid federal taxes (R. 11290).

The Municipals' attack on the Commission's holdings stems from their dissatisfaction with the concept of area ratemaking. Certainly, there is no justification for placing the pipeline producers at a competitive disadvantage by depriving them of tax deductions in years when these exceed taxable income, particularly when the area rate is devoid of any income tax allowance to compensate for such loss in years when taxable income is incurred. As the Commission stated (R. 11289-90):

> "If, as we hold, pipelines engaged in production activities are to be treated in the future, on newly acquired leaseholds, as though they were independent producers, and afforded a per Mcf price for gas taken into their systems totally unrelated to their particular

costs, particular rate of return considerations, or particular tax situation, then we believe they should be placed on a par in all respects. This should include the availability to the individual pipeline as a result of its production activities of any tax credits or its incurrence of any tax liability."

The arguments advanced by Municipals regarding taxes and rates of return are essentially the same as the contentions which were made regarding differences among classes of independent producers—small producers as compared with average producers—and which were rejected by the Tenth Circuit in *Skelly Oil Co.* v. *FPC,* 375 F.2d at 29, with the apt observation that:

> "The weakness of the argument is that once the whole group is split the process can be carried on until the regulation is back on an individual company basis."

Not only is the argument erroneous, but it achieves nothing because the existence of dispersions and disparities as among individual members or classes of the overall group does not affect the validity of the group ratemaking principle, as we now show.

B. Cost Dispersions Among Various Producers

The reported cases demonstrate the number and variety of objections which were raised against group ratemaking. But the least tenable of those objections is the one which underlies virtually all of the Municipals' contentions in the instant proceeding, namely that a large number of the individual members of the group would experience costs either above or below the average or norm selected as the group price. Of course this is true, as it simply paraphrases the definition of group ratemaking. By the same token the objection does not gain substance through characterizing those which experience above average success as receiving "windfalls", and the less efficient as being denied a "fair return." This simply paraphrases the paraphrase of the definition.

Yet, throughout their brief, Municipals have attempted to attack the Commission's substantive findings with little more than assertions that disparities or dispersions exist among members of groups or classes (Brief, pages 9; 30-1; 37-8). The Commission found these contentions unpersuasive, the more so because the same points had been unsuccessfully urged upon the Commission and the courts in the second *Phillips* case, *Permian Basin* cases, *Southern Louisiana* cases, and *Hunt Oil* case.

In devoting their attention to selected instances of historic cost differences among pipeline producers, the Municipals seek to ignore the fact that an equivalent range of disparities existed among independent producers, but this did not inhibit the Commission, with court approval, from applying area rates. The alleged cost differences discussed by the Municipals relate to capitalization ratios and unit costs (Brief, p. 30).[26]

However, the variation in capital structure for pipeline and affiliates ranged from 11.67% to 68% debt which is not essentially greater than the variation in capital structures of independent producers, ranging from 0% to 69% debt (R. 6146-8). The unit costs on a historical basis, for the various pipelines and affiliates ranged from 2.63 cents to 111.84 cents per Mcf, while the unit costs for the various independent producers ranged from 1.83 cents to 83.73 cents per Mcf, exclusive of state production taxes (R. 5908-10). There is thus no substance to the Municipals' claim that "the pipelines' cost variances are quite different from those of the independent producers" (Brief, p. 37).

[26] It is interesting to note that the Municipals have now abandoned a test applied by their policy witness, namely the ratio of production investment to revenues. The ratio for pipelines is 2.03, virtually identical to the 2.08 ratio for independent producers (R. 3665). The witness acknowledged that this testimony had been carried over from the Municipals' presentation in the *Southern Louisiana Area Rate Proceeding,* where it had been used to support their thesis that production of natural gas by independent producers is not "so different from the operations of public utilities that the cost-of-service method is less applicable, if at all, to the gas producing industry" (R. 3664-6).

Finally, the Municipals urge that because of possible future cost dispersions, the use of area rates will adversely affect those pipelines which incur above average costs, and will force them to discontinue their production activities (Brief, p. 9, 31). Surely this is not a distinction between pipeline producers and independent producers, to which these same area rates, based on averages, are now being applied. Stating, "We reject this attack as the Supreme Court rejected it in *Permian*", the Fifth Circuit expressly held that "there is nothing in either the Constitution or the Natural Gas Act that prevents the Commission from adopting price ceilings under which some producers will make more money than others or even under which some producers may be in danger of going out of business", *Southern Louisiana Area Rate Cases* (slip opinion, p. 41). The concern professed by the Municipals for the protection of future high-cost pipeline producers, is thus not a legal basis for overturning the Commission's decision here.

C. The Current Supply Situation

In the face of a diminishing supply of natural gas in relation to the nation's fuel requirements, and an absolute decline in pipeline-owned production, the Commission was understandably concerned that its decision in the instant proceeding not result in further diminution of future gas reserves (R. 11281; 11284). In their brief, the Municipals assail the Commission's reliance upon "untested extra-record material" to support its conclusions (Brief, pp. 63-69).

In the first place, the Commission's knowledge of whether a gas shortage is impending and its awareness of the possibility that future demand will outstrip supply unless remedial actions are taken, cannot be limited to the confines of a record made two or three years ago. Municipals do not create a genuine issue by questioning the precise derivation of knowledge which is now shared, not only by

experts such as the Commission, but by all informed persons.

The only item referred to by the Commission, to which the Municipals specifically object is the report for 1968 prepared by the American Petroleum Institute and the American Gas Association Committee on Reserves, which annually tabulates the reserves of oil, liquids and natural gas. Municipals are not even superficially correct in contending that the Commission erred in relying upon this item without affording Municipals the opportunity for cross-examination (Brief, page 65). The facts are that the continuing series of this particular report is one of the items designated at the outset of the hearings as "published statistical data included in Docket No. RP66-24 Proceeding", and was, therefore, a recognized source of information (R. 251-6, Item 19). Moreover, contrary to the assertion that the AGA data are not entitled to consideration, may we point out that these same statistics form the basis for the costing of new gas in the Commission's *Permian Basin* and *Southern Louisiana* area rate determinations, see 40 FPC 562.

Even if the material now objected to by the Municipals had not been designated as a specific data source for the instant proceeding, the Commission is entitled to take official notice "of such matters as might be judicially noticed by the courts of the United States, or any matters as to which the Commission by reason of its function is an expert." Rule 1.26(d), Federal Power Commission Rules of Practice and Procedure, 18 C.F.R. 1.26(d). Data on adequacy of gas reserves is clearly in an area of the Commission's expertise. Rule 1.26(d) provides that upon request any party shall be offered "an opportunity to show to the contrary" on any matter officially noticed. Municipals did not make such a request. Even now they do not demonstrate that gas reserves additions have not declined. Nor can they offer to show that there is no impending gas shortage.

Under comparable circumstances, the Commission's use of American Gas Association data, although not included in the record, was upheld in *Alabama-Tennessee Natural Gas Co.* v. *FPC,* 359 F.2d 318 at 339, cert. den. 385 U.S. 847 (1966), as follows:

> "On the record before us *and the facts outside of the record which the Commission properly notices,* the Commission's ruling is based on substantial evidence of present conditions and a fair guess as to future conditions in the pipeline industry."

In addition, there was substantial evidence in the record regarding the sharply decreasing trend of the ratio of national reserves to production (R. 5885-6), the even sharper decline in reserves owned by pipeline producers (R. 5888), and the ratio of reserves owned by pipeline producers to total committed reserves (R. 5889).

Indeed, the chief executive officer of one of the pipeline companies testified, in 1967, concerning the increasing difficulty in purchasing gas from independent producers, that the trend for new supplies is adverse, and, prophetically, that a shortage could occur "three years from now", or in 1970 (R. 3102-4; 719).[27]

The Commission also specifically relied upon gas supply data compiled by its staff and introduced into the record in this proceeding (R. 11359).

The judicial concern as to the current gas supply conditions and remedial action to avoid the progressively worsen-

---

[27] The witness also testified that it is not possible to purchase new gas from independent producers at a price lower than the Commission's ceiling, and that this condition will continue into the future (R. 3126). The Municipals argue that the Commission's decision will preclude pipeline producers from bargaining for the lowest obtainable rate, in seeking new supplies (Brief, page 43). This argument was not addressed to the Commission on rehearing and thus cannot be considered by the court. *FPC* v. *Sunray DX Oil Co.*, 391 U.S. 9 (1968). It was, nevertheless, fully answered by the testimony of the pipeline witness.

ing gas shortage, is reflected in the Fifth Circuit's recent opinion in *Southern Louisiana Area Rate Cases,* under the heading "The Current Supply Situation" (slip opinion, pp. 52-56). Based upon data and reports even more recent than those to which the Municipals object in the instant case, the Fifth Circuit stated that "the circumstances that have developed since its decision indicate a possibility, indeed perhaps a certainty, that the supply of gas is dangerously low."

Under the circumstances, the Commission was clearly justified, if not obliged, to relate its decision concerning future pipeline and affiliate production, to the public's need for adequate gas supplies. The method which it has chosen to assist in coping with this national problem is surely a product of its expertise, and merits approval on that basis. *Alabama-Tennessee Natural Gas Co.* v. *FPC, supra.*

IV.

THE COMMISSION ACTION CONSTITUTES ADJUDICATION AS WELL AS RULE MAKING

The final argument advanced by Municipals attacks the Commission's order on grounds that the Commission allegedly converted the proceeding from adjudication and reached its determination on the basis of rule making (Brief, pp. 57-58).

It is somewhat difficult to comprehend the purport of the criticism voiced by the Municipals, or to understand what it is that the Commission should have done that it did not do. If, by adjudication, the Municipals mean that the order should be based on the evidentiary record, the simple answer is that the Commission did base its action on the record, referring to the record throughout its decision. If, on the other hand, the Municipals are arguing that the Commission is legally precluded from making policy decisions as to rates in a rule making proceeding, they are totally in error.

It is pertinent to note that the problem with which the Municipals profess concern now is one which they themselves deemed pointless during the course of the proceeding below. They stated to the Commission (R. 7860):

> "It is by no means clear that the present proceeding is not in the nature of rulemaking. The key point is not the label of the proceeding but whether evidence is required."

In any event, the Commission's decision has only future applicability and is thus the proper subject for rule making. Rule making is defined in the Administrative Procedure Act, 5 U.S.C. § 551 as:

> "an agency statement of general . . . applicability and future effect designed to . . . prescribe a policy . . ."

Municipals argue that the instant proceeding has been "treated" as an area rate proceeding, but without following the adjudicatory procedures normally employed. This is contrary to the principles established by this Court in *State of Wisconsin* v. *FPC*, 303 F.2d 380 at 387, as follows:[28]

> "We must remember that the problem at bar concerns a regulatory power. We are not considering adjudicatory, or quasi-judicial, power. It has long since been established that rate-making is a legislative function, and it is so defined in the Administrative Procedure Act."

Even more recently, the Fifth Circuit, in rejecting a claim that a particular Commission determination subjecting producer sales to area rates, was required to be made after an adjudicatory hearing, stated:[29]

> "Furthermore, it would ignore the basic character of area rate regulation, which is in the nature of a rule-

[28] This Court has also underscored the need for flexible agency procedures in promulgating policies to govern future agency action. *American Airlines* v. *CAB*, 123 U.S. App. D.C. 310, 359 F.2d 624 (1966).

[29] *Hunt Oil* v. *FPC*, 5th Cir. No. 27457, April 21, 1970.

> making proceeding. Area rates are quasi-legislative rather than quasi-judicial in that they involve considerations that apply industrywide. If adjudicatory facts —facts governing the applicability of rates to particular persons as distinguished from facts applying broadly across the industry—had been an issue, then a hearing might be necessary, see K. Davis, Administrative Law Treatise, §§ 7.02, 7.04 (1958, Supp. 1965), but the responses to the show cause order disclosed no adjudicatory issues. We think that the reasoning of the *Permian* and *Southern Louisiana* cases rejecting the producers section 4 arguments also applies here."

In view of the foregoing, and in light of the detailed findings upon which the Commission based its action, it seems clear enough that the Commission's order is a product of both adjudication and rule making. It is not subject to any infirmity on procedural grounds.

CONCLUSION

For these reasons, the Commission's orders in Phase I of the Pipeline Production Area Rate Proceeding should be affirmed.

Respectfully submitted,

Raymond N. Shibley
James J. Flood, Jr.
1120 Connecticut Avenue, N. W.
Washington, D. C. 20036

Wm. Warfield Ross
1320 19th Street, N. W.
Washington, D. C. 20036

Attorneys for Intervenor Pipeline Production Group

June 15, 1970

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ILLINOIS, *et al.*,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

BRIEF FOR INTERVENOR-RESPONDENT TENNECO OIL COMPANY

JOHN E. WATSON
Tenneco Oil Company
P. O. Box 2511
Houston, Texas 77001

BARCLAY D. MCMILLEN
1361 Stratford Drive
Kent, Ohio 44240
Attorneys for Intervenor-Respondent
Tenneco Oil Company

Alpha Law Brief Co., M & M Bldg., Houston, Texas 77002

TABLE OF CONTENTS

TABLE OF CITATIONS

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23740

CITY OF CHICAGO, ILLINOIS, *et al.*,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

BRIEF FOR INTERVENOR-RESPONDENT TENNECO OIL COMPANY

STATEMENT OF ISSUES

I. Whether it is fair and equitable for the Federal Power Commission to continue the same pricing policy for natural gas sales by Tenneco Oil to its affiliated pipeline as for sales by other independent producers.

II. Whether the Federal Power Commission has been so strictured by the courts as to compel the Commission to require cost-of-service rate treatment for natural gas sold from leases acquired in the future by Tenneco Oil to its affiliated pipeline company.

STATEMENT OF THE CASE

This action arose from a proceeding of the Federal Power Commission (hereinafter referred to as the "FPC") instituted by order of April 13, 1966. By said order the FPC instituted a two-phase proceeding, only the first of which is here involved; that is, the determination of "the most appropriate pricing method to be applied to natural gas utilized in a pipeline's interstate system which is produced by the pipeline or its affiliated producing company from leases acquired *after the date of determination of this issue.*"[1] (Emphasis supplied).

Tenneco Oil Company (hereinafter referred to as "Tenneco Oil") was made a Respondent, but for purposes of the FPC hearing, was placed in a special group of respondents whose operations were uniquely like those of other independent producers. Extensive hearings were held with Tenneco Oil presenting both testimony and exhibits.[2]

The FPC in altering the decision of the Examiner of March 3, 1969,[3] in essence held that natural gas sold by pipelines and their affiliates to the pipeline company should receive the same rate as any other independent producer would receive for sales to said pipeline company.[4] This decision was in accord with the Supreme Court's upholding of the area pricing concept of the FPC in the Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

---

1. R. 7110 et. seq.

2. R. 723-729, 4046-4052, 5911-5917, and 5956-5965.

3. Opinion No. 568 (R. 11269) issued October 7, 1969 and Memorandum Opinion No. 568-A (R. 11357) denying rehearing issued December 5, 1969.

4. R. 10045-10171.

Tenneco Oil submits that the record below is abundantly clear and unrefuted that the operations of Tenneco Oil are those of an independent producer and *not* those of a "producing arm" of a pipeline company.

Tenneco Oil's production operations are not utility in nature, nor are they supply arms for utility distributor customers of Tennessee Gas Pipeline Company (Tennessee). The production activities of Tenneco Oil have never been directed toward the maintenance of adequate gas reserves for Tennessee's customers. On the contrary, Tenneco Oil is an integrated oil company operating on a world-wide basis.

Tenneco Oil's exploration and production activities are global, including not only widespread activity in the United States and the Gulf of Mexico, but, also, Africa, South America, the Near-East, and the North Sea. (See R. 724, 5911).

Tenneco Oil also has extensive operations for the marketing of its oil products. Products are sold at more than 1600 Tenneco Oil retail or wholesale outlets under the Tenneco brand or related brands in 35 states, the District of Columbia, and foreign lands. (R. 725, 5911).

Tenneco Oil Company is actively engaged in the production of extracted liquids through several processing plants. The operation of an underground LPG storage terminal and the distribution of LPG products are also encompassed within the operational areas of Tenneco Oil. Other areas of activity include the manufacture and sale of petro-chemical products, the marketing of potash to agricultural suppliers, and the marketing of insecticides and fertilizers.

ARGUMENT

I.

TO PREVENT UNJUST DISCRIMINATION IT IS FAIR, EQUITABLE, AND NECESSARY FOR THE FEDERAL POWER COMMISSION TO CONTINUE THE POLICY OF ALLOWING THE SAME RATES FOR SALES BY AN AFFILIATED INDEPENDENT PRODUCER LIKE TENNECO OIL AS FOR SALES BY OTHER INDEPENDENT PRODUCERS.

A. Any Differential Between Rates Which Tenneco Oil Could Charge For Natural Gas Sold To Its Affiliate And That Which Non-Respondent Producers Could Charge Would Discriminate Against Tenneco Oil When Competing In Legitimate Business Ventures With Other Producers.

Tenneco Oil is continually seeking new sources of oil and gas supply. In the acquisition of leases, Tenneco Oil must compete with other independent producers who may be seeking to acquire the same leasehold interests. From whom are these leases acquired?—obviously from a landowner who has leasable oil and gas rights. It is the general practice within the industry that royalties received by the landowner are based upon the price received by the producer. If Tenneco Oil were negotiating for a lease from which, within economic feasibility, gas production could only be sold to Tennessee, no sane landowner would lease his rights to Tenneco Oil if by so doing he would receive a price less than he would receive from a competing producer.[5] The effect of such a price differential would be to prevent the legitimate business ventures of Tenneco

5. R. 4047, 4048.

Oil and to restrict gas supply sources for affiliated pipelines.

However, this is not the only discriminatory and disadvantageous result which would flow from a rate differential. The continual need to discover and expand sources of gas supply and the recognition of the tremendous expense incurred in such exploration and production has necessitated many so-called "joint ventures" between groups of producers who share expenses. Any rate differential would severely restrict Tenneco Oil or any other producer affiliate from entering into "joint ventures" with other independent producers when economic feasibility would require the producer to sell its share of gas to a particular pipeline, for example, when the only feasible market for Tenneco Oil's share of gas would be Tennessee. Although all participants would ratably participate in the expenses of joint ventures, Tenneco Oil's revenues from the venture would be less than the revenues of non-affiliated producers, if there existed any rate differential between affiliated and non-affiliated producers. Again, the result of a rate differential would jeopardize gas supply sources for affiliated pipelines, would disadvantage Tenneco Oil's legitimate business ventures, and constitute unjust discrimination between affiliated and non-affiliated producers. Even if the venture with the price differential were economically feasible for Tenneco Oil, any rate differential would remain unjustly discriminatory.[6]

There are still other adversities which Tenneco Oil would suffer if a rate differential were adopted. Assume that Tenneco Oil discovers gas for which there are only two feasible customers, Tennessee and XYZ Pipeline. If

6. R. 4048, 4049.

under FPC regulatory treatment Tenneco Oil could charge Tennessee, say only 19¢ per Mcf, but could charge XYZ Pipeline the full area price of say 21¢ per Mcf, it is unlikely that XYZ Pipeline would be willing to pay the full price of 21¢. More than likely, XYZ would offer Tenneco Oil something like 19½¢ per Mcf, just enough sweetener to make its offer the better of the two. However, assume the only feasible customer other than Tennessee was not one which would make the sale subject to FPC jurisdiction, but, rather, would make the sale in intrastate commerce. In such an intrastate sale, the price could be as much as 25¢ per Mcf. Again, the prospective purchaser probably would offer Tenneco Oil just enough to make its offer a little sweeter than that which Tenneco Oil could lawfully charge its affiliate pipeline. These inequities would not occur if Tenneco Oil were allowed the area price.

The discriminatory effects of any price differential are not limited to the above. When any affiliated producer has uncommitted gas reserves, he should be able to negotiate on an equal basis with all pipeline purchasers in the area just like non-affiliated independent producers. This will not be the case if affiliated producers must sell their gas to an affiliated pipeline at prices different than those paid to non-affiliated producers.

There are ancillary questions raised in contending that Tenneco Oil should receive something different for its gas sold to Tennessee than would be received by non-affiliated producers. Not only would such constitute adverse discrimination as to Tenneco Oil but rate differentials would give non-affiliated producers preferential treatment by eliminating, in those instances applicable, competition from affiliated producers.

B. Any Rate Differential Would Force Affiliated Producers To Avoid Future Sales To Affiliated Pipelines.

The reality of the result of any rate differential will be either that affiliated producers will be economically prohibited from acquiring interests in leases when the only economically feasible market is the affiliated pipeline or that, in other instances, affiliated producers will not commit their uncommitted reserves to affiliated pipelines. The latter possibility constitutes a real danger in promulgating any pricing method providing for a rate differential between affiliated and non-affiliated producers.

If an affiliated producer has two potential customers for a gas supply, one the affiliated pipeline and the other a non-affiliated pipeline, good business judgment would dictate a sale where the best price could be obtained, all other factors being equal.

C. Price Uncertainty Would Result From The Adoption Of Cost-Of-Service Pricing As Proposed By Petitioners.

If cost-of-service pricing is made applicable to an affiliated producer, the price of gas sold to its pipeline affiliate by such producer will be dependent upon some future cost-of-service determination. Because of this uncertainty, the affiliated producer will be unable to forecast revenues and make other relevant management decisions which are necessary in evaluating any future gas prospect.

In contrast, no such uncertainty infects non-affiliated producer sales which are based upon pure area rates. The *Permian* case, *Permian Basin Area Rate Cases,* 380 U.S. 747 (1968), upheld the concept of area pricing and hear-

ings have either been commenced or completed which will determine the price for 90% of all natural gas sold in interstate commerce by independent producers.[7] Thus, today independent producers either know the price they will receive for natural gas sales subject to FPC jurisdiction or can anticipate knowing within the near future. Meanwhile, affiliated producers would have to await the outcome of still another proceeding to know the price they could charge for sales of gas to their affiliated pipeline.

Thus, another distinctly disadvantageous and discriminatory result will inure to affiliated producers should cost of service pricing be ordered.

II.

THE COURTS HAVE NOT SO STRICTURED THE FEDERAL POWER COMMISSION AS TO COMPEL THE COMMISSION TO REQUIRE COST-OF-SERVICE RATE TREATMENT FOR NATURAL GAS SOLD BY TENNECO OIL TO ITS AFFILIATE PIPELINE COMPANY.

To an appreciable degree in respect to the above issue and related areas, Tenneco Oil relies upon the brief to be submitted by the Pipeline Production Group. However, additionally, a few points should be noted.

Petitioners cite *City of Detroit v. FPC,* 97 U.S. App. D.C. 260, 230 F.2d 810 (D.C. Cir. 1955); cert. denied, 352 U.S. 829 (1956) and related cases, as requiring cost-

---

7. Brief for the Federal Power Commission, pp. 14-15 before the United States Supreme Court, *Permian Basin Area Rate Cases,* decided May 1, 1968.

of-service treatment in the instance proceeding. Those cases, which involved the pricing of pipeline produced gas transported by the pipeline company, are clearly distinguishable from the instant case upon four grounds:

(1) The issue in this proceeding, unlike in Petitioners' cited cases, is not the price of gas produced from existing leases but from leases acquired after the effective date of the FPC order herein. In a period of growing gas shortages, a pricing method for the future must have flexibility which the area pricing method does afford;

(2) *City of Detroit* involved a pipeline production department and not an affiliated independent producer like Tenneco Oil;

(3) Those cases were decided before the Supreme Court's 1968 approval of the FPC's area pricing policy for gas sold by independent producers; the ramifications of the area pricing concept affecting pipeline producers and affiliates were undoubtedly behind the FPC's order commencing this proceeding; and

(4) In reaching its pricing method in the cited cases the FPC did not have available the extensive cost data present in this record.

Petitioner's arguments are, therefore, at odds with the facts in this proceeding.

Tenneco Oil submits that the FPC correctly took into consideration the possibility of an impending natural gas shortage in making its determination below which is here

for review. Petitioner's attempts to whitewash[8] what the FPC and the industry now clearly recognize—a critical gas shortage—are not persuasive. The FPC appropriately took administrative notice of the April 7, 1969 report of the AGA Committee on Annual Gas Reserves, and, indeed, this Court should take judicial notice of the most recent of such reports for the year 1969, released April 8, 1970, which disclosed that for the nation, proved reserves declined for the second year in a row and by 12.2 trillion cubic feet (a decline almost equal to total production as recently as 1959); production in 1969 was more than twice reserves added; the Reserves to Production ratio fell precipitously to 13.3; and the Findings to Production ratio fell to 0.40.

The United States Court of Appeals for the Fifth Circuit in Southern Louisiana Area Rate Cases *Austral Oil Co., et al. v. FPC,* No. 27492, et al., decided March 19, 1970 at sl. op. pp. 52-54 took note of the current gas supply situation in stating:

> "Despite the Commission's optimistic conclusion, the circumstances that have developed since its decision indicate a possibility, indeed perhaps a certainty, that the supply of gas is dangerously low. A serious shortage, in fact, may already be unavoidable because present conditions may render any remedial action ineffective in light of the lag time between remedy and result. Thus the producers point out to us that the FP ratio, for the first time since World War II, shows that findings have declined below production. In other words, the gas industry in 1968 took more gas out of the ground than it discovered. Together with a growing production curve, this fact

8. Petitioner's Brief, pages 13, 14, 63-69.

> is alarming, especially since it is likely that the FP ratio will remain below 1.0 for the foreseeable future.[96] [9] The producers also contend that the RP ratio is dangerously low, and despite the frequency with which this argument has been effectively categorized as a 'cry of wolf',[97] we are concerned about it here. A majority of the Commissioners on the FPC have alluded in public speeches to the seriousness of the supply problem.[98] And an even more persuasive indication of the immediacy of the problem is the recent FPC Staff *Report on National Gas Supply and Demand*, issued October 1, 1969, which concludes that 'only a few years remain before demand will outrun supply.'[99]"

In respect to judicial notice of speeches by FPC Commissioners, the Fifth Circuit in footnote 98 to the above said, "We take judicial notice of the concerns these speeches express. *See* C. McCormick, Evidence § 328 at 704 (1954). (We do not, of course, take judicial notice of the specific facts they state for the purpose of resolving contested issues. *Id.*)"

CONCLUSION

The FPC, after carefully weighing all of the evidence presented in the proceeding below, held that pipelines and producer affiliates should receive the same rates as other independent producers; i.e., the area rates. Tenneco Oil submits that the expertise of the FPC should be upheld.

---

9. Footnotes omitted.

Therefore, for the reasons heretofore stated, it is respectfully requested that this Honorable Court affirm in full the FPC decision in this proceeding.

Respectfully submitted,

JOHN E. WATSON
Tenneco Oil Company
P. O. Box 2511
Houston, Texas 77001

BARCLAY D. MCMILLEN
1361 Stratford Drive
Kent, Ohio 44240
Attorneys for Intervenor-Respondent
Tenneco Oil Company

June 15, 1970